Maximum Achievable Control Technology Approval

Issued To: Roundup Power Project
P.O. Box 1697
Helena, Montana 59624

For Permit: #3182-00
Complete Application Submitted: 07/22/02
Preliminary Determination on the Initial Notice of MACT Approval: 07/25/03
Department Decision on the Final Notice of MACT Approval: 11/26/03
Final Notice of MACT Approval Issued: 06/04/04
AFS #: 065-0003

A Notice of Maximum Achievable Control Technology (MACT) Approval, with conditions, is hereby granted to the Roundup Power Project (Roundup Power), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, and 40 CFR 63, Subpart B. This notice establishes federally enforceable MACT emission limitations and requirements for Roundup Power's main boilers.

SECTION I: Permitted Facilities

A. Permitted Equipment

Roundup Power is proposing to construct and operate a nominal 780-megawatt (MW) pulverized coal (PC)-fired power plant. A complete list of the permitted equipment is contained in the attached MACT approval analysis.

B. Plant Location

The proposed location for the Roundup Power coal-fired power plant is approximately 12 miles south-southeast of the town of Roundup, Montana. The site is located immediately east of U.S. Route 87 just north of Old Divide Road and adjacent to the BMP Investments Incorporated coal mine. The legal description of the site is the NW¼ of the SE¼ of Section 15, Township 6 North, Range 26 East in Musselshell County.

SECTION II. Conditions and Limitations

A. Operational and Emission Limitations

1. Roundup Power shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and ARM 17.8.342).

2. Oxides of nitrogen (NO_x) emissions from each of the two main boilers shall be controlled with the use of low-NO_x burners (LNB), overfire air, and selective catalytic reduction (SCR). NO_x emissions from each main boiler shall not exceed 401.3 lb/hr (0.10 lb/MMBtu) based on a 1-hour average (ARM 17.8.342 and ARM 17.8.749).

3. NO_x emissions from each of the main boilers shall not exceed 280.9 lb/hr (0.07 lb/MMBtu) based on a rolling 24-hour average (ARM 17.8.342).

4. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the NO_x emissions from the two main boilers does not exceed 2,291.5 tons during any rolling 12-month time period. Any calculations used to establish NO_x emissions shall be approved by the Department of Environmental Quality (Department) and shall be based on the NO_x emissions measured by the continuous emission monitor system (CEMS) for each main boiler, unless otherwise allowed by the Department (ARM 17.8.342 and ARM 17.8.749).

5. Carbon monoxide (CO) emissions from each of the two main boilers shall be controlled by proper boiler design and operation. CO emissions from each main boiler shall not exceed 602.0 lb/hr (0.15 lb/MMBtu) (ARM 17.8.342).

6. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the CO emissions from the two main boilers does not exceed 4,910.4 tons during any rolling 12-month time period. Any calculations used to establish CO emissions shall be approved by the Department (ARM 17.8.342 and ARM 17.8.749).

7. Sulfur dioxide (SO_2) emissions from each of the two main boilers shall be controlled with the use of a dry flue gas desulfurization (FGD) system (spray dry absorber (SDA) FGD). SO_2 emissions from each main boiler shall not exceed 602.0 lb/hr (0.15 lb/MMBtu) based on a 1-hour average (ARM 17.8.342 and ARM 17.8.749).

8. SO_2 emissions from each of the two main boilers shall not exceed 481.6 lb/hr (0.12 lb/MMBtu) based on a rolling 24-hour average (ARM 17.8.342).

9. The control efficiency of the SO_2 emission control equipment for each main boiler, as measured by the inlet SO_2 CEMS (or the "as fired" fuel monitoring system) and the outlet SO_2 CEMS, shall be maintained at a minimum of 90% based on a rolling 30-day average (ARM 17.8.340, ARM 17.8.342, and 40 CFR 60, Subpart Da).

10. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the SO_2 emissions from the two main boilers does not exceed 3928.3 tons during any rolling 12-month time period. Any calculations used to establish SO_2 emissions shall be approved by the Department and shall be based on the SO_2 emissions measured by the CEMS for each main boiler, unless otherwise allowed by the Department (ARM 17.8.342).

11. Particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) emissions from each of the two main boilers shall be controlled with the use of a fabric filter (FF) baghouse (ARM 17.8.342).

    a. PM_{10} emissions from each main boiler shall not exceed 60.2 lb/hr (0.015 lb/MMBtu).

    b. After the first 18 months of operation, Roundup Power shall determine the feasibility of changing the PM_{10} emission limit for each main boiler from 60.2 lb/hr (0.015 lb/MMBtu) to 48.2 lb/hr (0.012 lb/MMBtu). The results of Roundup Power's analysis shall be submitted to the Department no later than 30 days after the first annual PM_{10} source tests.

12. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the PM_{10} emissions from the two main boilers does not exceed 491.0 tons during any rolling 12-month time period. Any calculations used to establish PM_{10} emissions shall be approved by the Department (ARM 17.8.342 and ARM 17.8.749).

13. Volatile Organic Compound (VOC) emissions from each of the two main boilers shall be controlled by proper boiler design and operation. VOC emissions from each main boiler shall not exceed 12.0 lb/hr (0.0030 lb/MMBtu) (ARM 17.8.342).

14. Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the VOC emissions from the two main boilers does not exceed 98.2 tons during any rolling 12-month time period. Any calculations used to establish VOC emissions shall be approved by the Department (ARM 17.8.342 and ARM 17.8.749).

15. Sulfuric Acid (H_2SO_4) Mist emissions from each of the two main boilers shall be controlled with the use of an SDA FGD. H_2SO_4 emissions from each main boiler shall not exceed 25.7 lb/hr (0.0064 lb/MMBtu) (ARM 17.8.342).

16. Construction of the Roundup Power facility must begin within 18 months of permit issuance and proceed with due diligence until the project is complete or the Notice of MACT approval will expire, unless otherwise approved by the Department as provided in ARM 17.8.342(9) and 40 CFR 63.43(g)(4) (ARM 17.8.342 and 40 CFR 63).

17. Mercury emissions from each main boiler shall be controlled with an SCR unit, SDA FGD, and an FF baghouse. Mercury emissions from each main boiler shall not exceed 0.00000269 lb/MMBtu based on a 1-hour average (ARM 17.8.342 and 40 CFR 63, Subpart B).

18. The emissions of acid gases (such as HF and HCl) from each of the main boilers shall be controlled with an SDA and an FF baghouse. The main boiler SO_2 and particulate matter emission limits shall be used as surrogate emission limits for acid gases (ARM 17.8.342 and 40 CFR 63, Subpart B).

19. Hydrogen fluoride (HF) emissions from each main boiler shall not exceed 0.00032 lb/MMBtu based on a 1-hour average (ARM 17.8.342 and 40 CFR 63, Subpart B).

20. Hydrogen chloride (HCl) emissions from each main boiler shall not exceed 0.0017 lb/MMBtu based on a 1-hour average (ARM 17.8.342 and 40 CFR 63, Subpart B).

21. The emissions of organic compounds from each of the main boilers shall be controlled by proper boiler design and operation. The main boiler CO and VOC emission limits shall be used as surrogate emission limits for organic compounds (ARM 17.8.342 and 40 CFR 63, Subpart B).

22. The emissions of radionuclides from each of the main boilers shall be controlled by an FF baghouse. The main boilers PM_{10} emission limits shall be used as surrogate emission limits for radionuclides (ARM 17.8.342 and 40 CFR 63, Subpart B).

23. The emissions of trace metals from each of the main boilers shall be controlled by an FF baghouse. The main boilers PM_{10} emission limits shall be used as surrogate emission limits for trace metals. In addition, the emissions of trace metals shall not exceed the following limits (ARM 17.8.342 and 40 CFR 63, Subpart B):

Arsenic	3.8E-03 lb/hr (9.41E-01 lb/TBtu)
Beryllium	1.2E-04 lb/hr (3.00E-02 lb/TBtu)
Cadmium	2.5E-03 lb/hr (6.30E-01 lb/TBtu)
Chromium	1.1E-02 lb/hr (2.79E+00 lb/TBtu)
Manganese	3.1E-02 lb/hr (7.81E+00 lb/TBtu)
Nickel	1.1E-02 lb/hr (2.73E+00 lb/TBtu)
Lead	1.3E-02 lb/hr (3.36E+00 lb/TBtu)

24. In addition to complying with this case-by-case MACT determination, Roundup Power shall comply with the electric utility MACT upon promulgation, within the timeframes allowed by 40 CFR 63, Subpart B (ARM 17.8.342 and 40 CFR 63, Subpart B).

25. Roundup Power shall comply with 40 CFR 63, Subpart A and Subpart B, as applicable (ARM 17.8.342 and 40 CFR 63).

B. Testing Requirements

1. Roundup Power shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the opacity limit contained in Section II.A.1, for each of the main boilers (ARM 17.8.749).

2. Roundup Power shall use the data from the NO_x CEMS to monitor compliance with the NO_x emission limits contained in Section II.A.2, Section II.A.3, and Section II.A.4, for each of the main boilers (ARM 17.8.105 and ARM 17.8.749).

3. Roundup Power shall test each of the two main boilers for CO within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the CO emission limits contained in Section II.A.5 and Section II.A.6. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

4. Roundup Power shall use the data from the SO_2 CEMS to monitor compliance with the SO_2 emission limits contained in Section II.A.7, Section II.A.8, Section II.A.9, and Section II.A.10, for each of the main boilers (ARM 17.8.105 and ARM 17.8.749).

5. Roundup Power shall test each of the two main boilers for PM_{10} within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the PM_{10} emission limits contained in Section II.A.11.a and Section II.A.12, to determine the feasibility of meeting an emission limit based on 0.012 lb/MMBtu (Section II.A.11.b), and to monitor compliance with the emission limits contained in Section II.A.23. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

6. Roundup Power shall test each of the two main boilers for H_2SO_4 within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the H_2SO_4 emission limit contained in Section II.A.15. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.710).

7. Roundup Power shall test each of the two main boilers for mercury within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the mercury emission limit contained in Section II.A.17. The testing of each boiler shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

8. Roundup Power shall test each of the two main boilers for HF within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the HF emission limit contained in Section II.A.19. The testing of each boiler shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

9. Roundup Power shall test each of the two main boilers for HCl within 180 days of initial start-up of the respective boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the HCl emission limit contained in Section II.A.20. The testing of each boiler shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

10. Roundup Power shall collect a sample of the coal "as fired" in conjunction with the initial mercury source tests and the subsequent annual mercury source tests. The coal sample shall be analyzed for mercury, chlorine, and fluorine content. This information shall be used to establish a correlation between the coal's mercury, chlorine, and fluorine content and the main boiler's mercury, HCl, and HF emissions (ARM 17.8.105 and ARM 17.8.749).

11. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual and 40 CFR 63, Subpart A (ARM 17.8.106).

12. The Department may require further testing (ARM 17.8.105).

C. Operational Reporting Requirements

1. Roundup Power shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. Roundup Power shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by Roundup Power as a permanent business record for at least 5 years following the date of collection, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. Roundup Power shall document, by month, the amount of NO_x emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the NO_x emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.4. A written report, including the previous 12-month total of NO_x emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.749).

5. Roundup Power shall document, by month, the amount of CO emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the CO emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.6. A written report, including the previous 12-month total of CO emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.749).

6. Roundup Power shall document, by rolling 30-day period, the percentage of SO_2 removed from the gas stream by the SO_2 control equipment. By the 25th day of each month, Roundup Power shall calculate the SO_2 removal efficiency during each rolling 30-day period that expired during the previous month to verify compliance with the limitation in Section II.A.9. A written report, including the previous 12 months of rolling 30-day SO_2 removal efficiencies for the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.749).

7. Roundup Power shall document, by month, the amount of SO_2 emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the SO_2 emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.10. A written report, including the previous 12-month total of SO_2 emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.749).

8. Within 30 days after conducting the first annual PM_{10} source test, Roundup Power shall submit an analysis of the feasibility of meeting a PM_{10} emission limit of 48.2 lb/hr (0.012 lb/MMBtu). The analysis shall be based on the initial source testing results and the first annual source testing results (ARM 17.8.749).

9. Roundup Power shall document, by month, the amount of PM_{10} emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the PM_{10} emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.12. A written report, including the previous 12-month total of PM_{10} emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.749).

10. Roundup Power shall document, by month, the amount of VOC emissions from the two main boilers. By the 25th day of each month, Roundup Power shall total the VOC emissions from the two main boilers during the previous 12 months to verify compliance with the limitation in Section II.A.14. A written report, including the previous 12-month total of VOC emissions from the two main boilers, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual emission inventory (ARM 17.8.749).

D. Continuous Monitoring System Requirements

1. Roundup Power shall install, operate, calibrate, and maintain continuous monitoring systems for the following:

   a. A CEMS for the measurement of SO_2 shall be operated on each main boiler stack (ARM 17.8.340; 40 CFR 60, Subpart Da; 40 CFR 60, Subpart Db; and 40 CFR 72-78).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on each main boiler stack (40 CFR 72-78).

   c. A CEMS for the measurement of NO_x shall be operated on each main boiler stack (ARM 17.8.340; 40 CFR 60, Subpart Da; 40 CFR 60, Subpart Db; and 40 CFR 72-78).

d. A COMS for the measurement of opacity shall be operated on each main boiler stack (ARM 17.8.340; 40 CFR 60, Subpart Da; 40 CFR 60, Subpart Db; and 40 CFR 72-78).

e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on each main boiler stack (ARM 17.8.340 and 40 CFR 60, Subpart Da).

f. A CEMS for the measurement of CO_2 content shall be operated on each main boiler stack (40 CFR 72-78).

2. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Da; 40 CFR Part 60, Subpart Db; 40 CFR Part 60, Appendix B (Performance Specifications #1, #2, and #3); and 40 CFR Part 72-78, as appropriate (ARM 17.8.340; 40 CFR 60; and 40 CFR 72-78).

3. On-going quality assurance requirements for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749).

4. Roundup Power shall inspect and audit the COMS annually, using neutral density filters. Roundup Power shall conduct these audits using the appropriate procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report (ARM 17.8.749).

5. Roundup Power shall maintain a file of all measurements from the CEMS (including the performance testing measurements); all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; all adjustments and maintenance performed on these systems or devices. The measurements shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements. Roundup Power shall supply these records to the Department upon request (ARM 17.8.749).

6. Roundup Power shall maintain a file of all measurements from the COMS (including the performance testing measurements); all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; all adjustments and maintenance performed on these systems or devices. The measurements shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements. Roundup Power shall supply these records to the Department upon request (ARM 17.8.749).

E. Notification

1. Roundup Power shall provide the Department (both the Billings regional and Helena offices) with written notification of the following dates within the specified time periods (ARM 17.8.749):

a. Commencement of construction of the power generation facility within 30 days after commencement of construction

b. Anticipated start-up date of the facility postmarked not more than 60 days nor less than 30 days prior to start-up

c. Actual start-up date of the first main boiler within 15 days after the actual start-up of the boiler

d. Actual start-up date of the second main boiler within 15 days after the actual start-up of the boiler

2. Roundup Power shall notify the Department of all compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. Roundup Power shall promptly notify the Department by telephone of any malfunction that occurs that can be expected to create emissions in excess of any applicable emission limitation or can be expected to last for a period greater than 4 hours (ARM 17.8.110).

4. Roundup Power shall provide the Department (both the Billings regional and Helena offices) with written notification of the following items within 30 days after actual startup of the power generation facility, or according to another schedule as may be approved by the Department (ARM 17.8.749):

   a. Make, model, type, size, serial number, year of manufacture, and year of installation of all proposed process equipment identified in Section 4.0 of Montana Air Quality Permit Application #3182-00.

   b. Make, model, type, size, serial number, year of manufacture, and year of installation of all proposed control equipment identified in Section 5.0 of Montana Air Quality Permit Application #3182-00.

Maximum Achievable Control Technology Analysis
Roundup Power Project
For Permit #3182-00

I. Introduction/Process Description

A. Permitted Equipment

The Roundup Power Project (Roundup Power) facility will be located approximately 35 miles north of Billings and 12 miles south-southeast of the town of Roundup. The facility's primary equipment will consist of the following:

- Two coal fired generating units, each with a pulverized coal (PC)-fired boiler and a steam turbine-generator with a nominal electrical output of 390-megawatt (MW) (main boilers). Each of the main boilers would be fitted with a dry Flue Gas Desulfurization (FGD) system (spray dry absorber – SDA), a Selective Catalytic Reduction (SCR) system, and a pulse jet fabric filter baghouse (FF). The main boilers will use coal as their primary fuel and No.2 fuel oil for startup.
- Two air-cooled condensers
- Two auxiliary boilers fueled with No.2 fuel oil
- One emergency generator fueled with No.2 fuel oil
- Storage and handling equipment for coal, lime, ash, and No.2 fuel oil
- 4000-foot long overland conveyor

B. Source Description

Coal for the main boilers would be supplied by the BMP Investments Incorporated coal mine that is located on the adjacent property immediately to the east of the power plant location. The coal would be transferred to the power plant via a 4000-foot long overland conveyor. The coal that is transferred to the power plant facility would be stored in either the active coal storage pile or in the inactive coal storage pile. The inactive coal storage pile would consist of approximately 92,500 tons of coal (11 days worth of coal storage for the power plant).

From the 25,000-ton active coal storage pile (Transfer House 1), coal would be transferred to the reclaim hoppers and then on to the crusher house. From the crusher house, coal would be transferred via conveyors to the main boilers for combustion.

C. Permit History

On January 14, 2002, Roundup Power submitted a permit application for a nominal 780 MW coal fired power plant to be located near Roundup, Montana. An application for a case-by-case Maximum Achievable Control Technology (MACT) determination was submitted in addition to the permit application. After resolving the deficiency issues with the original permit application, the permit application was deemed complete on July 22, 2002. Because the Department of Environmental Quality (Department) did not include a case-by-case MACT determination in Permit #3182-00 when it was issued as a Preliminary Determination (PD), the Department decided that the most appropriate time for a case-by-case MACT determination would be after issuance of Permit #3182-00, in a process outside of the original permitting for the facility.

D. Current Action

The current action for this facility reflects Roundup Power's application for a case-by-case MACT Determination and the Department's subsequent MACT determination. Numerous conditions in the MACT determination are identical to the conditions in Permit #3182-00. However, inclusion of those conditions in this document indicates the Department's reliance on those conditions in this MACT determination.

E. Project Schedule

At the time of Roundup Power's initial permit application submittal, commencement of construction of the facility was expected to begin in April of 2002. Based on this schedule, the construction of the first generating unit was expected to be complete in mid 2005, with commercial service beginning in October of 2005. The second unit was expected to be complete by early to mid 2006, with commercial service beginning in October 2006. Based upon the time required for the initial permitting process and the subsequent challenges to the permit decision for the Roundup Power facility, the project schedule is not certain at this time.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available, upon request, from the Department. Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in the chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

   Initial performance tests are required for the main boilers as directed by the applicable New Source Performance Standards (NSPS). Continuous emission monitoring systems (CEMS) will be required to be used on each main boiler exhaust to monitor ongoing oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) compliance. Continuous opacity monitoring systems (COMS) will be required to be used on each main boiler exhaust to monitor ongoing compliance with the opacity limitations. Initial source testing will be used to monitor compliance with the carbon monoxide (CO), particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}), mercury, hydrogen fluoride (HF), and hydrogen chloride (HCl) emission limits for the main boilers. The PM_{10} testing results will be used as an indicator of compliance with the trace metal limits. Additional testing of each main boiler will be required annually for CO, PM_{10}, and mercury, every 5 years for HF, and every 2 years for HCl.

   The Department used its December 4, 1998, guidance statement titled "Revised Testing Schedule" as a guide to determining the appropriate testing schedule for the Hazardous Air Pollutants (HAP). The guidance identifies a suggested testing frequency based upon the magnitude of uncontrolled emissions. Although the guidance was established for emissions of criteria pollutants, the same general concept was used by the Department to establish a testing frequency for HAPs. However, based on comments submitted during the public comment period and additional Department research into the mercury testing requirements for other sources, the Department determined that a more stringent emission-testing schedule was appropriate for mercury. Source testing, coal analyses, and continuous monitoring of certain emission parameters (SO_2, NO_x, and opacity) will be used as the method of monitoring the efficacy of the control equipment and, therefore, monitoring compliance with the emission limits.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in the chapter, or any permit or order issued pursuant to the chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   Roundup Power shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

   1. ARM 17.8.204 Ambient Air Monitoring
   2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
   3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
   4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
   5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
   6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
   7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
   8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
   9. ARM 17.8.222 Ambient Air Quality Standard for Lead
   10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

   Roundup Power must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

   1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

   2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, Roundup Power shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. Roundup Power shall comply with this rule by combusting low sulfur coal and by applying emission controls for removal of SO_2 from the combustion gases.

6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). Roundup Power is considered an NSPS affected facility under 40 CFR 60 and is subject to the requirements of the following subparts.

   40 CFR Part 60, Subpart A – General Provisions. This subpart applies to all affected equipment or facilities subject to an NSPS subpart as listed below.

   40 CFR 60, Subpart Da, Standards of Performance Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. The main boilers at Roundup Power are affected facilities under this subpart because 1) the electric utility steam generating units are capable of combusting more than 73-MW heat input of fossil fuel and 2) the construction of the facility would occur after September 18, 1978.

   40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The auxiliary boilers at Roundup Power are affected facilities under this subpart because 1) the steam generating units will commence construction after June 19, 1984 and 2) the facility will have a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW. The main boilers are not subject to this subpart because this subpart defines an "affected facility" as a steam generating unit that is not subject to Subpart Da. The main boilers are subject to Subpart Da.

   40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants. The coal handling equipment at Roundup Power are affected facilities under this subpart because 1) the equipment (such as breakers and crushers) meets the definition of a coal preparation facility as defined in §60.251 and 2) the facility would process more than 200 tons of coal per day.

8. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR 61.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. This source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63. The current determination satisfies the case-by-case MACT requirement as specified in ARM 17.8.342 and 40 CFR 63. Roundup Power is considered an affected facility under 40 CFR 63 and is subject to the requirements of the following subparts.

   40 CFR 63, Subpart A – General Provisions. This subpart applies to all affected equipment or facilities subject to the provisions of 40 CFR 63.

40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) and 112(j). Electric utility steam generating units are subject to this subpart because on December 14, 2000, EPA published a finding that the regulation of HAP emissions from coal-fired and oil-fired electric utility steam generating units was appropriate and necessary. As a result, coal-fired and oil-fired electric utility steam generating units were added to the list of source categories under Section 112(c) of the Act. The exclusion for electric utility steam generating units in 40 CFR 63, Subpart B is no longer in effect because electric utility steam generating units were added to the source category list on December 20, 2000 [Federal Register Notice, Volume 65, Number 245, Pages 79825-79831] pursuant to Section 112(c)(5) of the Clean Air Act. Although these units have been identified as a new source category under Section 112(c) of the Act, EPA has not yet developed MACT standards for the category. The main boilers are the only emission units classified as "coal-fired electric utility steam generating units" at the Roundup Power facility. Therefore, only the two main boilers at the Roundup Power facility are subject to the MACT provisions of 40 CFR 63, Subpart B.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in the chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. Roundup Power must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). Roundup Power made the appropriate demonstration of compliance with the ambient air quality standards.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. Roundup Power submitted the appropriate permit application fee for Permit #3182-00. The application fee submitted for Permit #3182-00 satisfies any fee requirements for the current case-by-case MACT determination.

2. ARM 17.8.505 When Permit Required--Exclusions. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of the rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in the chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. Roundup Power has the PTE more than 25 tons per year of several criteria pollutants; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits—Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration or use of a source. Roundup Power submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Roundup Power submitted an affidavit of publication of public notice for the January 18, 2002, issue of the *Billings Gazette*, a newspaper of general circulation in the city of Billings in Yellowstone County, as proof of compliance with the public notice requirements. Roundup Power submitted a second affidavit of publication of public notice for the January 23, 2002, issue of the *Roundup Record-Tribune* and *The Winnett Times*, newspapers of general circulation in the area of the project, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of the subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that Best Available Control Technology (BACT) shall be utilized. A BACT analysis was not required for the current case-by-case MACT determination. However, the information submitted by Roundup Power for the BACT analysis and the Department's BACT determination were both relied upon as part of the MACT determination.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving Roundup Power of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in the subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued. Roundup Power is required to begin construction within 18 months of permit issuance, or the permit will be revoked.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in the subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as the subchapter would otherwise allow.

   This facility is a listed source because it is a fossil fuel fired steam-electric plant having more than 250 MMBtu/hr heat input. Furthermore, the facility's emissions are greater than 100 tons per year. Therefore, the facility is a major source under the New Source Review (NSR)-Prevention of Significant Deterioration (PSD) program.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. This rule contains a list of applicable definitions used in this subchapter. Under definition (23) "major source" is defined as a major source under Section 7412 of the FCAA, which is any source having:

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one HAP, PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

c. PTE > 70 tons/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing the Notice of MACT Approval for Air Quality Permit #3182-00 for Roundup Power, the following conclusions were made.

   a. The facility's PTE is greater than 100 tons/year for PM_{10}, SO_2, NO_x, and CO.

   b. The facility's PTE is greater than 10 tons/year for an individual HAP and greater than 25 tons/year for the combination of all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to several current NSPS.

   e. This facility is currently subject to case-by-case MACT (40 CFR 63, Subpart B).

   f. This source is a Title IV affected source.

   g. This source is not an EPA designated Title V source.

   Based on these facts, the Department determined that Roundup Power is a major source of emissions as defined under the Title V Operating Permit Program.

III. BACT Determination

A BACT determination is not required for the current MACT determination. However, the BACT determination reached through Permit #3182-00 was relied upon for the case-by-case MACT determination. Copies of the BACT analysis submitted by Roundup Power, the BACT information submitted/analyzed during the permit process, and the corresponding Department BACT determination for Permit #3182-00 are on file with the Department. The Department is relying on the requirements established through the BACT process to provide control for HAPs. The emission controls and emission limits established through the BACT process for criteria pollutants (NO_x, CO, SO_x, PM_{10}, etc.) will also provide emission controls for HAPs. As described later in this MACT analysis, this same type of approach has been used by other permitting agencies in recent case-by-case MACT determinations. For example, the acid gases (HCl and HF) and organic compounds will be controlled in the SDA/FF system that Roundup Power is required to install and operate as part of the BACT determination for SO_2 and PM_{10} emissions. The radionuclides, trace metals, and mercury emissions will be controlled in the FF system that Roundup Power is required to install and operate as part of the BACT determination for PM_{10} emissions. Additional mercury control will also be achieved with the use of the SCR system required through the BACT determination for NO_x emissions and the SDA system required through the BACT determination for SO_x emissions.

IV. Case-by-Case MACT

A. MACT Requirements

Roundup Power submitted a MACT analysis for HAPs emitted from the main boilers with the original permit application. Roundup Power submitted the MACT analysis with its permit application to satisfy the requirements of 40 CFR 63 and ARM 17.8.302. Roundup Power submitted additional information regarding the MACT analysis later during the permitting process for the facility. The information submitted by Roundup Power, as well as the extensive research performed by the Department and comments submitted on the PD, formed the basis for the Department's determination regarding MACT.

MACT is an emission control standard that was added to the Clean Air Act by the Clean Air Act Amendments of 1990. MACT is defined in ARM 17.8.301 as:

> *The emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that the Department, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source of HAP.*

40 CFR 63.41 defines "similar source" as:

> *A stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology.*

According to 40 CFR 63.55, the emission limitation established by the Department shall not be less stringent than the MACT floor and shall be based on available information and information generated by the Department before or during the application review process, including information provided in public comments. 40 CFR 63.51 defines "MACT floor" as:

(1) For existing sources:

- (i) The average emission limitation achieved by the best performing 12 percent of the existing sources in the United States (for which the Administrator has emission information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined in section 171 of the Act) applicable to the source category and prevailing at the time, in the category or subcategory, for categories and subcategories of stationary sources with 30 or more sources; or
- (ii) The average emission limitation achieved by the best performing five sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory, for categories and subcategories with fewer than 30 sources.

(2) For new sources, the emission limitation achieved in practice by the best controlled similar source.

If it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a HAP or HAPs, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of Section 112(d) and Section 112(f) of the FCAA. In addition, 40 CFR 63 allows a specific design, equipment, work practice, or operational standard if it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the FCAA. Section 112(h)(2) of the FCAA defines "not feasible to prescribe or enforce an emission standard" as any situation in which the Administrator determines that:

1. A HAP or HAPs cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or

2. The application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The first criterion is not an issue because the Roundup Power HAPs would be emitted through the main boiler stacks. According to Roundup Power, the second criteria, however, is an issue for this facility. Although this section of the FCAA appears to be directed toward promulgating standards for a class of sources rather than an individual source, the fact remains that there is a lack of existing data available to effectively establish emission limitations for each applicable HAP. Therefore, Roundup Power proposed multi-pollutant controls (i.e. low NO_X burners with selective catalytic reduction, two spray dry absorbers, and two baghouses) rather than emission limitations for each HAP. Although these technologies were originally intended to control criteria pollutants, recent data shows that they are also effective in controlling some HAPs. The Department agrees, in part, with Roundup Power's assertion that the second criteria (application of measurement methodology) are not practicable for all HAPs. However, as described later in this document, the Department does believe that specific MACT emission limits are appropriate for mercury, HF, HCl, and trace metals. The Department does not believe that the application of measurement technology to the remaining HAPs is technologically and/or economically reasonable. Instead, the Department determined that adequate surrogate emission limits exist for the HAPs. In addition to the specific limits for mercury, HF, HCl, and trace metals, the Department determined that the emission limits for the criteria pollutants represent surrogate MACT emission limits for the remaining HAPs by category (radionuclides, organic compounds, etc.).

The Department used "available information" to determine the applicability of criteria 1 and criteria 2 to the HAPs emitted from the Roundup Power main boilers. "Available information" was also used to determine the appropriate MACT emission limits for those HAPs that can feasibly be prescribed an emission limit that is enforceable. "Available Information" is defined in 40 CFR 63.51 as "…information contained in the following information sources as of the section 112(j) deadline:

· A relevant proposed regulation, including all supporting information,

· Background information documents for a draft or proposed regulation,

· Any regulation, information or guidance collected by the Administrator establishing a MACT floor finding and/or MACT determination,

· Data and information available from the Control Technology Center developed pursuant to Section 112(1)(3) of the Act,

· Data and information contained in the Aerometric Information Retrieval System (AIRS) including information in the MACT database,

· Any additional information that can be expeditiously provided by the Administrator, and

· Any information provided by applicants in an application for a permit, permit modification, administrative amendment, or Notice of MACT Approval pursuant to the requirements of this subpart."

A relevant proposed regulation, including all supporting information, was not available at the time of this MACT determination, nor were background information documents for a draft or proposed regulation. However, the Department reviewed numerous other sources of "available" information before making the following proposed MACT determination. Among other research, the Department researched EPA's RACT/BACT/LAER Clearinghouse, information on EPA's Technology Transfer Network (TTN) website, EPA's Case-by Case MACT Tool, information presented at the Western Mercury Workshop (April

2003), information submitted by Roundup Power, other information submitted to the Department regarding Roundup Power, the Utility Air Toxics Report to Congress (Utility RTC), and MACT determinations made for other coal-fired power plants. The Department specifically reviewed recent MACT determinations for 9 other coal-fired power plants. The specific MACT determinations researched by the Department were for the following facilities:

- Plum Point Energy Associates, LLC – Plum Point Energy Station;
- MidAmerican Energy Company – Council Bluffs Energy Center;
- EnviroPower of Illinois, LLC;
- Corn Belt Energy Corporation, Elkhart;
- Kentucky Mountain Power, LLC;
- Black Hills Corporation – WYGEN 2 Facility;
- Thoroughbred Generating Company, LLC – Thoroughbred Generating Station;
- Southern Illinois Power Cooperative; and
- Tucson Electric Power Company – Springerville Generating Station.

The Department researched recent MACT determinations by first looking up recent coal-fired power plant projects (see www.epa.gov/ttn/catc/products.html#misc) and by then looking up the specific projects identified on this list (see www.state.sc.us/states). The Department looked up the recent MACT determinations made throughout the nation to ensure that the MACT determination for Roundup Power factored in recent MACT determinations.

The MACT requirements in 40 CFR 63 have been incorporated by reference into ARM 17.8.302. MACT regulations apply to any owner or operator who plans to construct a major source of HAPs. A facility is classified as a major source of HAPs if it has the potential to emit 10 tons per year (tpy) of any HAP or 25 tpy of any combination of HAPs. The list of pollutants defined as hazardous is included in Section 112(b) of the Act. Potential HAP emissions from the proposed Roundup Power facility are discussed in the permit application. The project is classified as a major source of HAP emissions because of the potential to emit more than 10 tpy of HCl and 10 tpy of HF and the potential to emit more than 25 tpy of a combination of all HAPs.

Initially, electric utility steam generating units were excluded from the MACT requirements. 40 CFR 63.40(c) states: "The requirements of [40 CFR 63 Subpart B] do not apply to electric utility steam generating units unless and until such time as these units are added to the source category list pursuant to Section 112(c)(5) of the Act." However, on December 14, 2000, EPA published a finding that the regulation of HAP emissions from coal-fired and oil-fired electric utility steam generating units was appropriate and necessary. As a result, coal-fired and oil-fired electric utility steam generating units were added to the list of source categories under Section 112(c) of the Act. The exclusion for electric utility steam generating units in 40 CFR 63, Subpart B is no longer in effect because electric utility steam generating units were added to the source category list on December 20, 2000 [Federal Register Notice, Volume 65, Number 245, Pages 79825-79831] pursuant to Section 112(c)(5) of the Clean Air Act. Although these units have been identified as a new source category under Section 112(c) of the Act, EPA has not yet developed MACT standards for the category. The main boilers are the only emission units classified as "coal-fired electric utility steam generating units" at the Roundup Power facility. Therefore, only the two main boilers at the Roundup Power facility are subject to the MACT provisions.

Until the promulgation of the electric utility MACT standards, any construction or reconstruction of a coal-fired or oil-fired electric utility steam-generating unit that has the potential to be a major source of HAPs is subject to a "case-by-case" MACT determination (FCAA, Section 112(g)). The requirements for a case-by-case MACT determination are included in ARM 17.8.342(3) and ARM 17.8.342(4). The Montana regulations state that case-by-case MACT determinations must be based on the standards specified in 40 CFR

63.43(d) and 63.43(e). Because the MACT standards have not been promulgated for electric utility steam-generating units, Roundup Power is subject to a "case-by-case" MACT determination by the Department. Roundup Power submitted a permit application and corresponding MACT analysis on January 14, 2002, for the power generation facility. The application was deemed complete on July 22, 2002.

B. Potential HAP Emissions from the Coal-fired Electric Utility Steam Generating Units

The EPA finding published on December 20, 2000, was based on results of EPA's February 1998 "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress" (the Utility RTC). The Utility RTC was based on HAP emissions test data gathered from 52 utility units including a range of coal-fired, oil-fired, and natural gas-fired boilers. A screening level hazard/risk assessment was completed for 67 of the 189 HAPs listed in Section 112(b) of the FCAA. Based on the results of the screening assessment, 14 HAPs were further analyzed by EPA. The 14 HAPs were analyzed for inhalation and/or multi-pathway exposures and risks. The priority HAPs identified in the Utility RTC are listed in the following table.

Table 1. Priority HAPs identified in the Utility RTC

Pollutant	Classification
Hydrogen Chloride (HCl)	Acid gas
Hydrogen Fluoride (HF)	Acid gas
Mercury	Metal
Lead	Metal
Arsenic	Metal
Beryllium	Metal
Cadmium	Metal
Chromium	Metal
Manganese	Metal
Nickel	Metal
Acrolein	Organic compound
Dioxins	Organic compound
Formaldehyde	Organic compound
Radionuclides	Radionuclides

Of the 14 HAPs identified by EPA in its Utility RTC as priority, mercury was identified as the HAP of greatest concern. EPA also identified arsenic, chromium, nickel, and cadmium as a potential concern for carcinogenic effects, and stated that "although the results of the risk assessment indicate that cancer risks are not high, they are not low enough to eliminate those metals as a potential concern for public health." With regards to the other HAPs, EPA concluded that "[t]he other HAPs studied in the risk assessment do not appear to be a concern for public health based on the available information. However, because of data gaps and uncertainties, it is possible that future data collection efforts or analyses may identify other HAPs of potential concern." EPA specifically identified HCl, HF, and dioxins as three HAPs that may be evaluated further during the regulatory development process.

C. HAP Control Strategies

The Department analyzed control technologies as part of the MACT determination for the HAPs. 40 CFR 63.51 defines *control technology* as "measures, processes, methods, systems, or techniques to limit the emission of HAPs including, but not limited to, measures which:

- Reduce the quantity, or eliminate emissions, of such pollutants through process changes, substitution of materials or other modifications,

- Enclose systems or processes to eliminate emissions,

- Collect, capture, or treat such pollutants when released from a process, stack, storage or fugitive emissions point,
- Are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in 42 U.S.C. 7412(h), or
- Are a combination of paragraphs (1) through (4) of this definition."

Although it is unknown which HAPs will ultimately be subject to control as a result of EPA's electric utility source category rulemaking, Roundup Power proposed a case-by-case MACT analysis for the 14 priority HAPs identified in EPA's Utility RTC. The MACT assessment was prepared for the priority HAPs based on the following classifications: acid gases, organic compounds, radionuclides, trace metals, and mercury. The Department agrees that a MACT assessment based on these classifications is appropriate because the classifications are consistent with recent MACT determinations and with the utility RTC.

Public comments were submitted during the public comment period that suggested that Integrated Gasification Combined Cycle (IGCC) should have been considered as part of the MACT analysis and subsequent MACT determination. Even though IGCC was considered in the initial BACT analysis and the subsequent contested case hearing on the preconstruction permit for Roundup Power, consideration of IGCC is not required by MACT, nor does the Department believe that consideration of IGCC in the MACT determination is appropriate. Although the argument may be made that IGCC and PC boilers have comparable emissions and can be controlled with the same control technologies, IGCC is not a "similar source" as mentioned in the MACT definition because IGCC is not structurally similar in design and capacity to the proposed PC boilers such that it would be considered a similar source and achieving lower emissions with an IGCC unit on a PC boiler is not possible. In addition, IGCC was not determined to constitute BACT in the Department's initial BACT analysis and the subsequent contested case hearing; therefore, the Department did not consider IGCC to be an appropriate consideration in the MACT process. Furthermore, IGCC has not been required as part of case-by-case MACT determinations for PC boilers.

1. Control of Acid Gases

Two priority HAPs, HF and HCl, are characterized as acid gases. Acid gases represent the large majority of potential HAPs from Roundup Power. Based on emission calculations, HCl and HF would constitute approximately 97% of all HAPs emitted from the main boilers. The amount of HCl and HF generated in the boilers would be dependent on the chlorine, fluorine, and ash content of the coal.

a. Emission Limitation Achieved In Practice by the Best Controlled Similar Source

In its Utility RTC, EPA reviewed existing data on the removal efficiencies of HCl and HF by conventional air pollution control devices. EPA's test report data specified the following:

i. Electrostatic Precipitators (ESP) removed less than 6% of the acid gases
ii. FFs removed approximately 44% of the HCl and essentially none of the HF
iii. Wet FGD with 15% bypass was estimated to remove approximately 80% of the HCl and approximately 29% of the HF
iv. Spray Dry Absorber and FF (SDA/FF) with 14% bypass were estimated to remove approximately 82% of each acid gas

Both HCl and HF are water-soluble, and based on the finding in EPA's Utility RTC, they would be effectively controlled in the SDA/FF system that Roundup Power would use to control SO_2 and PM_{10} emissions from the main boilers. Roundup Power's

Permit #3182-00 would not allow flue gas to be bypassed around the SDA/FF system; therefore, the system should reduce emissions of both HCl and HF by at least 90%, as compared to the 82% removal efficiency described in Section IV.C.1.a.iv.

Based on published literature, Roundup Power proposed the use of an SDA/FF system as MACT for acid gases. The Department agrees that the use of an SDA/FF system constitutes MACT for acid gases. In addition, the Department determined that a MACT emission limit of 0.00032 lb/MMBtu for HF and a MACT emission limit of 0.0017 lb/MMBtu for HCl are appropriate. Acid gases generally react with lime (the reagent for the spray dryer/absorber) to form solids, which are removed in the baghouse. Since the lime spray dryer/absorber and FF would be operated to control SO_2 and PM_{10} emissions, respectively, the criteria pollutant controls would also control acid gases. The proposed emission limits for HF and HCl are consistent with other recent MACT determinations and are based upon a control efficiency of 90%. Other acid gas emission limits that have recently been established and that were identified by the Department during this MACT process are shown in Table 2.

Table 2. Recent HF/HCl MACT Determinations and the Roundup Power Determination

Company	HF Limit (lb/MMBtu)	HCl Limit (lb/MMBtu)	Control Technology
Plum Point Energy Associates, LLC – Plum Point Station	0.00044	0.013	SDA/FF
MidAmerican Energy Company – Council Bluffs Energy Center	No Limit	0.0029	SDA/FF
EnviroPower of Illinois, LLC	No Limit	No Limit	SDA/FF
Corn Belt Energy Corporation – Elkhart	No Limit	No Limit	Wet FGD/Wet ESP
Kentucky Mountain Power, LLC	0.0053	No Limit	NIDS/FF
Black Hills Corporation - Wygen 2	No Limit	No Limit	SDA/FF
Thoroughbred Generating Station Company, LLC	0.000159	No Limit	Wet FGD/Wet ESP
Southern Illinois Power Cooperative	Not Addressed	Not Addressed	Not Addressed
Tucson Electric Power Company – Springerville Generating Station	0.00044	No Limit	SDA/FF
Roundup Power Project	0.00032	0.0017	SDA/FF

Note: SDA/FF – Spray Dry Absorber/Fabric Filter
Wet FGD/Wet ESP – wet flue gas desulfurization/wet electrostatic precipitator
NIDS/FF – natural integrated desulfurization system/fabric filter

The Department determined that Roundup Power must maintain compliance with the HCl, HF, SO_2, and PM_{10} emission limits for MACT. Using the SO_2 and PM_{10} emission limits as surrogate emission limits for HF and HCl will provide a more frequent indication of Roundup Power's compliance with the HF and HCl emission limits (for example, the SO_2 CEMS). In order for Roundup Power to meet the HCl, HF, SO_2, and PM_{10} emission limits, the SDA/FF controls will have to be operated optimally. The emission controls and corresponding emission limits are consistent with recent MACT determinations, and the requirements are not less stringent than the emission limitations achieved in practice by the best-controlled similar sources. Of the sources researched by the Department, only the Thoroughbred Generating Station has a lower HF limit.

However, the Thoroughbred Generating Station HF limit is based upon a rolling 30-day average. The limit established by the Department for Roundup Power was based on the permit application and would be based upon a 1-hour average (the averaging time that corresponds to the relevant test method). Although the HF limit is a lower value for the Thoroughbred Generating Station, the averaging time must be considered. Shorter averaging times increase the stringency of limits. Of the HCl limits identified by the Department, the Roundup Power HCl limit would be the lowest and would be based upon the averaging time that corresponds to the relevant test method.

Other facilities, such as the Black Hills Power Corporation Wygen 2 (Wygen 2) facility and the MidAmerican Energy Company Council Bluffs (MidAmerican) facility were also considered prior to establishing the HF and HCl emission limits for Roundup Power in the Initial Notice of MACT Approval. Both of these facilities were referenced in comments that were submitted during the public comment period for this Notice of MACT Determination. For example, although the analysis for the Wygen 2 facility briefly describes a removal efficiency of 96% for both HF and HCl for the Wygen control equipment, corresponding emission limits for HF and HCl based on 96% control were not established in the air quality permit--no emission limits were established for HF or HCl. The MidAmerican permit does not contain an HF limit either. The MidAmerican permit and technical support document do appear to base the HCl emission limit on 96% control (based on the worst case chlorine content of any potential coal--548 ppm). The HCl emission limit established for MidAmerican was 0.0029 lb/MMBtu. The HCl emission limit established for Roundup Power is 0.0017 lb/MMBtu (based on 90% control). The established HCl emission limit for Roundup Power is approximately 58.6% lower than the HCl emission limit for MidAmerican. Therefore, the Department determined that the emission limit established in the Initial Notice of MACT Approval for Roundup Power is appropriate and the 96% control proposed by MidAmerican is not MACT for Roundup Power.

Basing emission limits specifically on control efficiency requirements for a similar source is not appropriate without consideration of case-by-case factors related to the proposed facility. Because the MidAmerican coal (analysis based upon 548 ppm) has chlorine content higher than that of Roundup Power's coal source (analysis based upon 200 ppm), it is much easier for MidAmerican to meet an HCl emission limit based upon 96% removal efficiency than for sources with lower chlorine content, such as at Roundup Power. Although the emission limit established for Roundup Power is considerably lower than the emission limits recently established for other facilities, the Department determined that the emission limit reflects the maximum degree of reduction in emissions possible, taking into consideration the cost of achieving such emission reduction, and non-air quality health and environmental impacts and energy requirements.

b. Costs of Achieving Emission Reductions

Since the top option for MACT for acid gases would be the same control technology that was required in the BACT analysis for SO_2 and PM_{10}, the costs of using this technology to control the acid gases would be economically reasonable. In order to maintain compliance with the SO_2, PM_{10}, HCl, and HF emission limits for the main boilers, Roundup Power will need to closely monitor the control equipment and maintain the equipment. Increased preventive maintenance on the equipment will result in increased costs for achieving the MACT emission limits.

The total annual cost for dry FGD (control equipment) for the main boilers was reported by Roundup Power to be $11,329,000. The cost effectiveness of using dry FGD for acid gases alone would be $35,150 per ton of HCl and HF reduction. This same annual control equipment cost equated to an SO_2 cost effectiveness of $393 per ton removed. Because dry FGD will reduce the emissions of SO_2 in addition to reducing the emissions of acid gases, the use of dry FGD becomes an economically reasonable method for acid gas control. Without the added benefit of reducing SO_2 emissions, the use of a dry FGD system would not be economically reasonable for controlling acid gas emissions.

The use of an FF system in conjunction with the dry FGD system is essential in the collection of SO_2 emissions and PM_{10} emissions. The total annual cost for FFs for the main boilers was reported by Roundup Power to be $4,063,000. The cost effectiveness of using FFs for acid gases alone would be $12,606 per ton of HCl and HF reduction. This same annual control equipment cost equated to a PM_{10} cost effectiveness of $31 per ton removed. Because FFs will reduce the emissions of PM_{10} in addition to reducing the emissions of acid gases, the use of FFs becomes an economically reasonable method for acid gas control. Without the added benefit of reducing PM_{10} emissions, the use of an FF baghouse would not be economically reasonable for controlling acid gas emissions.

Wet FGD was a potential control identified for controlling acid gases. The total annual cost for wet FGD (control equipment) for the main boilers was reported by Roundup Power to be $12,065,000. The cost effectiveness of using wet FGD for acid gases alone would be $37,434 per ton of HCl and HF reduction. This same annual control equipment cost equated to an SO_2 cost effectiveness of $409 per ton removed. Because wet FGD will reduce the emissions of SO_2 in addition to reducing the emissions of acid gases, the use of wet FGD becomes an economically reasonable method for acid gas control. Without the added benefit of reducing SO_2 emissions, the use of a wet FGD system would not be economically reasonable for controlling acid gas emissions.

The use of a wet ESP in conjunction with the wet FGD system is essential in the collection of SO_2 emissions and PM_{10} emissions. The total annual cost for wet FGD and wet ESPs for the main boilers was reported by Roundup Power to be $15,241,000. The cost effectiveness of using wet FGD and wet ESP for acid gases alone would be $47,288 per ton of HCl and HF reduction. This same annual control equipment cost equated to an SO_2 cost effectiveness of $517 per ton removed. Because wet FGD/wet ESP will reduce the emissions of SO_2 in addition to reducing the emissions of acid gases, the use of wet FGD/wet ESP becomes an economically reasonable method for acid gas control. Without the added benefit of reducing SO_2 and PM_{10} emissions, the use of wet FGD and wet ESP would not be economically reasonable for controlling acid gas emissions.

The use of a wet ESP (alone) was also analyzed. The total annual cost for ESPs for the main boilers was reported by Roundup Power to be $4,741,000. The cost effectiveness of using ESPs for acid gases alone would be $14,710 per ton of HCl and HF reduction. This same annual control equipment cost equated to a PM_{10} cost effectiveness of $36 per ton removed. Because ESPs will reduce the emissions of PM_{10} in addition to reducing the emissions of acid gases, the use of ESPs becomes an economically reasonable method for acid gas control. Without the added benefit of reducing PM_{10} emissions, the use of an ESP would not be economically reasonable for controlling acid gas emissions.

The HCl and HF cost effectiveness calculations in this section are based on 90% acid gas reduction (302.4 tons per year of uncontrolled HCl emissions and 55.7 tons per year of uncontrolled HF emissions).

The use of a wet FGD/wet ESP system for controlling acid gas emissions was eliminated as MACT control for other reasons as identified in Section IV.C.1.a and IV.C.1.c.

c. Non-Air Quality Health and Environmental Impacts and Energy Requirements

FGD systems use water. The lesser amount of water required by a dry FGD system in comparison to the amount of water required by a wet FGD system was one of the primary reasons that dry FGD was selected as BACT. Water usage was still an important factor in selecting dry FGD as MACT for acid gases. In addition, the dry FGD will not generate a wastewater stream, whereas a wet FGD system would generate a wastewater stream. Both FGD systems will generate a solid waste byproduct. In a dry FGD system, the solid waste byproduct will be captured as fly ash in the particulate control system. In a wet FGD system, the solid waste byproduct will be captured in water slurry and will be separated from the water by a "dewatering" process.

The particulate control options of FFs and ESPs will both generate a solid waste byproduct. The solid waste byproduct will be required to be disposed of in accordance with the applicable regulations. FFs will provide the highest level of particulate control. ESPs will require more energy than an FF system.

2. Control of Organic Compounds

Three compounds identified as priority HAPs in the Utility RTC are classified as organic compounds: acrolein, formaldehyde, and dioxins. Very limited data is available regarding the formation and control of organic compounds from utility boilers. For example, dioxin emissions data in the Utility RTC were only available for 12 utility plants, and 42% of the concentration measurements taken at those plants were so low that they were below the minimum detection limit of the analytical test equipment. Moreover, these hazardous organic compounds are not part of the naturally occurring fossil fuel, but are formed in highly complicated chemical reactions that occur with unknown frequency during combustion. In general, organic compounds are formed during the combustion of hydrocarbon-based fuels. Emissions from the combustion of hydrocarbon-based fuels are dependent on the completeness of the destruction of the organic compounds during the combustion process. Thermal oxidation (good combustion practices) is an effective means of destroying organics and has been used to control organic emissions from a wide variety of industrial processes. In thermal oxidation, organic compounds are oxidized in the combustion zone and are converted to CO_2 and water vapor. With efficient mixing, oxygen availability, adequate residence time, and adequate temperatures (generally in the range of 1470-1830°F); organic compounds, including dioxins, may be efficiently destroyed. Pulverized coal boilers provide all of the factors facilitating complete combustion including extended residence time, continuous mixing of the air and fuel, and consistent high temperatures in the combustion chamber.

a. Emission Limitation Achieved In Practice by the Best Controlled Similar Source

Information in the Utility RTC suggests that the emission control technologies used to control PM_{10} and SO_2 may also control dioxins and other organic compounds. The Utility RTC concludes that dioxins would be reduced by FFs (due to absorption onto the filter cake) and by an SDA/FF control system.

Because of the limited data regarding the formation and control of specific organic HAPs, it is not possible to provide a quantitative description of the control efficiency that will be achieved by the Roundup Power boilers. However, as described by Roundup Power, the combustion characteristics of the boilers designed to minimize emissions of CO and Volatile Organic Compounds (VOC) also tend to minimize the formation of dioxins, formaldehyde, and acrolein. Therefore, Roundup Power proposed good combustion controls and the inherent thermal oxidation characteristics of the boilers as MACT for organic compounds. Roundup Power further noted that if any organic compounds are present in the flue gas, they may be further reduced in the SDA/FF control system. The Department agrees with Roundup Power's proposal and determined that good combustion controls constitute the MACT control of organic compounds. The Department also determined that the main boiler CO and VOC emission limits will act as surrogate MACT limits for organic compounds. In order for Roundup Power to meet the CO and VOC emission limits in Permit #3182-00 for the main boilers, the combustion process would have to be operated optimally.

The emission controls and corresponding emission limits for CO and VOCs are consistent with recent MACT determinations, and the requirements are not less stringent than the emission limitations achieved in practice by the best-controlled similar sources. The Department identified specific MACT limits for organic compounds only at the Plum Point Energy Associates, LLC – Plum Point Station facility. All of the other facilities identified by the Department had permits with no specific organic compounds limit. All of the facilities identified by the Department that monitored organic compounds, including the Plum Point Energy Associates, LLC – Plum Point Station facility, did so with a surrogate measurement of VOC emissions.

b. Costs of Achieving Emission Reductions

Since the top option for MACT for organic compounds would be the same combustion technique that was required in the BACT analysis for CO and VOCs, the costs of using this technique to control the organic compounds would be economically reasonable. In order to maintain compliance with the CO and VOC emission limits for the main boilers (surrogate MACT emission limits for the organic compounds), Roundup Power will need to closely monitor the combustion process. The cost of using good combustion practices will not be an additional cost; therefore, good combustion practices are an economically reasonable method for controlling organic compounds.

The added benefit of controlling SO_2 and PM_{10} emissions will be the control of organic compounds that are created. The total annual cost for dry FGD for the main boilers was reported by Roundup Power to be $11,329,000. The cost effectiveness of using dry FGD for SO_2 emissions control was estimated to be $393 per ton removed. Because dry FGD will reduce the emissions of SO_2 in addition to reducing the emissions of organic compounds, the use of dry FGD becomes an economically reasonable method for organic compounds control. Without the added benefit of reducing SO_2 emissions, the use of a dry FGD system would not be economically reasonable for controlling organic compound emissions alone.

The use of an FF system in conjunction with the dry FGD system is essential in the collection of SO_2 and PM_{10} emissions. The total annual cost for FFs for the main boilers was reported by Roundup Power to be $4,063,000. The cost effectiveness of using FFs for PM_{10} emissions control was estimated to be $31 per ton removed. Because an FF system will reduce the emissions of PM_{10} in addition to reducing the emissions of organic compounds, the use of an FF system becomes an economically reasonable method for organic compounds control. Without the added benefit of reducing PM_{10} emissions, the use of an FF system would not be economically reasonable for controlling organic compound emissions.

Wet FGD is a potential control identified for controlling organic compounds. The total annual cost for wet FGD (control equipment) for the main boilers was reported by Roundup Power to be $12,065,000. Because of the limited data available on organic compounds control, determining the cost per ton of organic compound reduction for a wet FGD system is not practical. The cost effectiveness of using wet FGD for SO_2 would be $409 per ton removed. Because wet FGD will reduce the emissions of SO_2 in addition to reducing the emissions of organic compounds, the use of wet FGD becomes an economically reasonable method for organic compounds control. Without the added benefit of reducing SO_2 emissions, the use of a wet FGD system would not be economically reasonable for controlling organic compound emissions.

The use of a wet ESP in conjunction with the wet FGD system is essential in the collection of SO_2 emissions and PM_{10} emissions. The total annual cost for wet FGD and wet ESPs for the main boilers was reported by Roundup Power to be $15,241,000. Because of the limited data available on organic compounds control, determining the cost per ton of organic compound reduction for a wet FGD and wet ESP system is not practical. The cost effectiveness of using wet FGD and wet ESP for SO_2 would be $517 per ton removed. Because wet FGD/wet ESP will reduce the emissions of SO_2 in addition to reducing the emissions of organic compounds, the use of wet FGD/wet ESP becomes an economically reasonable method for organic compound control. Without the added benefit of reducing SO_2 and PM_{10} emissions, the use of wet FGD and wet ESP would not be economically reasonable for controlling organic compounds.

The use of an ESP (alone) was also analyzed. The total annual cost for ESPs for the main boilers was reported by Roundup Power to be $4,741,000. Because of the limited data available on organic compounds control, determining the cost per ton of organic compound reduction for a wet ESP system is not practical. The cost effectiveness of using ESPs for PM_{10} would be $36 per ton removed. Because ESPs will reduce the emissions of PM_{10} in addition to reducing the emissions of organic compounds, the use of ESPs becomes an economically reasonable method for organic compound control. Without the added benefit of reducing PM_{10} emissions, the use of an ESP would not be economically reasonable for controlling organic compound emissions.

The use of a wet FGD/wet ESP system for controlling acid gas emissions was eliminated as MACT control for other reasons as identified in Section IV.C.2.a and IV.C.2.c.

c. Non-Air Quality Health and Environmental Impacts and Energy Requirements

Good combustion practices will actually minimize the amount of fuel that is required in the boilers to meet the output goals. No other non-air quality health, environmental, or energy impacts were identified that would result from good combustion practices.

As described in Section IV.C.1.c, FGD systems use water. The amount of water required by a dry FGD system in comparison to the amount of water required by a wet FGD system was one of the primary reasons that dry FGD was selected as BACT. Water usage is still an important factor in selecting dry FGD as MACT for organic compounds. In addition, the dry FGD will not generate a wastewater stream, whereas a wet FGD system would generate a wastewater stream. Both FGD systems will generate a solid waste byproduct. In a dry FGD system, the solid waste byproduct will be captured as fly ash in the particulate control system. In a wet FGD system, the solid waste byproduct will be captured in water slurry and will be separated from the water by a "dewatering" process.

The particulate control options of FFs and ESPs will both generate a solid waste byproduct. The solid waste byproduct will be required to be disposed of in accordance with the applicable regulations. FFs will provide the highest level of particulate control. ESPs will require more energy than an FF system.

3. Control of Radionuclides

Nearly all natural materials, including coal, contain trace quantities of radioactivity. When coal is burned to produce steam in the production of electricity, radionuclides are entrained in the combustion gases. The radionuclide content of coal is not much different than for other natural materials.

a. Emission Limitation Achieved In Practice by the Best Controlled Similar Source

Radionuclides emitted from a coal-fired boiler are emitted primarily as particulate matter. Therefore, pollution control systems designed to reduce particulate matter, such as PM_{10} emissions, will also effectively reduce emissions of radionuclides. The Utility RTC states that particulate matter control devices at coal-fired utilities reduce radionuclide emissions by more than 95%.

Particulate matter emissions from Roundup Power's main boilers would be controlled with FFs expected to achieve an overall particulate control efficiency of about 99.82%. The FFs will also effectively remove radionuclides from the flue gas. Based on published literature, Roundup Power determined that FFs are the most effective technology for control of radionuclides. Roundup Power proposed FFs as MACT for radionuclides.

The other particulate control device that was analyzed was an ESP. ESPs also provide excellent control of particulate matter emissions. The particulate collection efficiency of an ESP was estimated to be about 99.78%. An ESP would also be expected to effectively remove radionuclides from the flue gas.

Because the FF system will result in greater emission reductions than the ESP system, the Department agrees with Roundup Power's proposal and determined that the FF baghouse is the appropriate MACT control for radionuclides. The Department also determined that the emission limit in Permit #3182-00 for PM_{10} would act as a surrogate MACT emission limit for radionuclides. In order for Roundup Power to meet the PM_{10} emission limits in Permit #3182-00, the FF baghouse will have to be operated optimally. The Department did not identify any other facilities that have a specific MACT limit for radionuclides. Therefore, the emission controls and corresponding emission limit are consistent with recent MACT determinations, and the requirements are not less stringent than the emission limitations achieved in practice by the best-controlled similar sources.

b. Costs of Achieving Emission Reductions

Since the top option for MACT for radionuclides would be the same control technology that was required in the BACT analysis for PM_{10}, the costs of using this technology to control the radionuclides would be economically reasonable. In order to maintain compliance with the PM_{10} emission limits for the main boilers (surrogate MACT emission limit for the radionuclides), Roundup Power will need to closely monitor the control equipment and maintain the equipment.

The use of an FF system is essential in the collection of PM_{10} emissions. The FF system will also be essential in the collection of radionuclides. The total annual cost for FFs for the main boilers was reported by Roundup Power to be $4,063,000. The cost effectiveness of using FFs for PM_{10} emissions control was estimated to be $31 per ton removed. Because an FF system will reduce the emissions of PM_{10} in addition to reducing the emissions of radionuclides, the use of an FF system becomes an economically reasonable method for radionuclides control. Without the added benefit of reducing PM_{10} emissions, the use of an FF system would not be economically reasonable for controlling radionuclide emissions.

In comparison, an ESP would also be essential in the collection of PM_{10} and radionuclides. The total annual cost for ESPs for the main boilers was reported by Roundup Power to be $4,741,000. Because of the trace quantities of radionuclides emitted, the use of an ESP system solely for radionuclide control would be unreasonable. However, the cost effectiveness of using ESPs for PM_{10} control would be $36 per ton removed. Because ESPs will reduce the emissions of PM_{10} in addition to reducing the emissions of radionuclides, the use of ESPs becomes an economically reasonable method for radionuclides control. Without the added benefit of reducing PM_{10} emissions, the use of an ESP would not be economically reasonable for controlling radionuclides.

c. Non-Air Quality Health and Environmental Impacts and Energy Requirements

The particulate control options of FFs and ESPs will both generate a solid waste byproduct as described in Section IV.C.1.c. The solid waste byproduct from the either unit will be required to be disposed of in accordance with the applicable regulations. FFs will provide the highest level of particulate control. ESPs will require more energy than an FF system.

4. Control of Trace Metals

Trace metals contained in coal are emitted during the combustion process. The quantity of any given metal emitted, in general, depends on:

- The physical and chemical properties of the metal itself
- The concentration of the metal in the coal
- The combustion conditions
- The type of particulate and SO_2 control devices used

Depending on the metal's physical and chemical properties and the boiler combustion conditions, some metals could be emitted in the gas phase, while others will be emitted as particulates and will tend to concentrate in either fly ash or bottom ash.

a. Emission Limitation Achieved In Practice by the Best Controlled Similar Source

Based on the physical and chemical properties of the metals listed as priority HAPs, most arsenic, beryllium, cadmium, chromium, manganese, and lead would be emitted as particulate oxides. EPA identified in the Utility RTC that these pollutants exist primarily in particulate form. High-efficiency particulate control devices readily control HAP metals that exist primarily in particulate form. Both FFs and ESPs will provide significant particulate matter control and have been required to be used by other sources.

As discussed previously, particulate matter emissions from Roundup Power's main boilers would be controlled with highly efficient FFs (≈99.82% control of PM_{10}). Because FFs generally achieve higher collection efficiencies (≈99.82%) than ESPs (≈99.78%), FFs were identified as the more desirable control option. The FFs will also be very effective in removing trace metal particulates from the boiler flue gas. Based on EPA emission data, the control efficiency for the trace metal particulates is expected to be greater than 95%. The only metal HAP that may not be effectively controlled by the FFs, alone, is mercury. The control of mercury is discussed in Section IV.C.5.

Based on published literature, Roundup Power determined that FFs are the most effective technology for control of trace metal HAPs, other than mercury. Roundup Power proposed FFs as MACT for metal HAPs, other than mercury. The

Department agrees with Roundup Power that FF baghouses are the appropriate MACT control for trace metals (other than mercury). Also, the Department determined that the PM_{10} emission limit contained in Permit #3182-00 would act as a surrogate MACT limit for trace metals. In addition, the Department determined that specific emission limits were appropriate for arsenic, beryllium, cadmium, chromium, manganese, mercury, nickel, and lead. In order for Roundup Power to meet the PM_{10} emission limit and trace metal limits, the FF baghouse will have to be operated optimally. The emission controls and corresponding emission limit are consistent with recent MACT determinations, and the requirements are not less stringent than the emission limitations achieved in practice by the best-controlled similar sources (See Table 3).

Table 3. Recent Trace Metals MACT Determinations and the Roundup Power Determination

Company	Trace Metals Limit	Compliance Demonstration	Control Technology
Plum Point Energy Associates, LLC – Plum Point Station	Contains lb/hr and tpy limits for trace metals	Compliance with PM_{10} limit	FF
MidAmerican Energy Company – Council Bluffs Energy Center	$1.04*10^{-4}$ lb/MMBtu on trace metals	Compliance with PM_{10} limit	FF
EnviroPower of Illinois, LLC	No specific limit	No specific compliance demonstration	FF
Corn Belt Energy Corporation – Elkhart	No specific limit	Testing for metals	Wet ESP
Kentucky Mountain Power, LLC	0.000194 lb/MMBtu for lead 0.0000217 lb/MMBtu for beryllium	Testing for lead, beryllium, mercury	FF
Black Hills Corporation - Wygen 2	No specific limit	Testing for metals and compliance with PM_{10} limit	FF
Thoroughbred Generating Station Company, LLC	0.00000386 lb/MMBtu for lead 0.000000944 lb/MMBtu for beryllium annual limits for arsenic, beryllium, chromium, manganese, cadmium, and mercury	Testing for arsenic, beryllium, chromium, manganese, chromium, cadmium, and mercury	Wet ESP
Southern Illinois Power Cooperative	Not Addressed	Not Addressed	Not Addressed
Tucson Electric Power Company – Springerville Generating Station	0.000016 lb/MMBtu for lead	Lead testing and compliance with PM_{10} limit	FF
Roundup Power Project	3.8E-03 lb/hr (9.41E-01 lb/TBtu) for arsenic, 1.2E-04	Compliance with PM_{10} limit	FF

	lb/hr (3.00E-02 lb/TBtu) for beryllium, 2.5E-03 lb/hr (6.30E-01 lb/TBtu) for cadmium, 1.1E-02 lb/hr (2.79E+00 lb/TBtu) for chromium, 3.1E-02 lb/hr (7.81E+00 lb/TBtu) for manganese, 1.1E-02 lb/hr (2.73E+00 lb/TBtu) for nickel, and 1.3E-02 lb/hr (3.36E+00 lb/TBtu) for lead		

Note: FF – Fabric Filter
Wet ESP – wet electrostatic precipitator

b. Costs of Achieving Emission Reductions

Since the top option for MACT for trace metals would be the same control technology that was required in the BACT analysis for PM_{10}, the costs of using this technology to control the trace metals would be economically reasonable. In order to maintain compliance with the PM_{10} emission limits for the main boilers (surrogate MACT emission limit for the trace metals), Roundup Power will need to closely monitor the control equipment and maintain the equipment as appropriate.

The use of an FF system is essential in the collection of PM_{10} emissions. The FF system will also be essential in the collection of trace metals. The total annual cost for FFs for the main boilers was reported by Roundup Power to be $4,063,000. The cost effectiveness of using FFs for PM_{10} emissions control was estimated to be $31 per ton removed. Because an FF system will reduce the emissions of PM_{10} in addition to reducing the emissions of trace metals, the use of an FF system becomes an economically reasonable method for trace metals control. Without the added benefit of reducing PM_{10} emissions, the use of an FF system would not be economically reasonable for controlling trace metal emissions.

For comparison, the cost effectiveness of using ESP control was also analyzed. The total annual cost for ESPs for the main boilers was reported by Roundup Power to be $4,741,000. The cost effectiveness of using ESPs for PM_{10} emissions control was estimated to be $36 per ton removed. Because an ESP system will reduce the emissions of PM_{10} in addition to reducing the emissions of trace metals, the use of an ESP system becomes an economically reasonable method for trace metals control. Without the added benefit of reducing PM_{10} emissions, the use of an ESP system would not be economically reasonable for controlling trace metal emissions.

c. Non-Air Quality Health and Environmental Impacts and Energy Requirements

The particulate control options of FFs and ESPs will both generate a solid waste byproduct as described in Section IV.C.1.c. The solid waste byproduct will be required to be disposed of in accordance with the applicable regulations. Fabric filters will provide the highest level of particulate control. ESPs require more energy than FFs.

5. Control of Mercury

Although FFs effectively control most trace metals, mercury requires additional consideration because it can be emitted as a mixture of solid and gaseous forms. In general, mercury in boiler flue gas would be in an elemental form (Hg^0), an ionic form (Hg^{2+}), or a particulate form (Hg(p)). The relative concentration of each form of mercury in the flue gas is termed mercury speciation. Each form of mercury has different physical and chemical characteristics, and conventional pollution control devices have varying control efficiencies for each of the forms. Mercury speciation for a coal-fired boiler would depend upon the combustion characteristics of the boiler as well as the characteristics of the feed coal.

Mercury emissions from a power plant are a function of several factors including fuel mercury content, fuel chlorine content, boiler type and operation, flue gas composition, and the type of emission controls used for criteria pollutants. According to Roundup Power, the mercury concentration of coal ranges from an average of approximately 2.5 pounds per trillion British thermal units (lb/TBtu) to approximately 20 lb/TBtu. The average mercury concentration of U.S. coal is reported in the utility RTC to be approximately 7.7 lb/TBtu. Based on available analyses of Bull Mountains coal, the mercury concentration of the fuel used for Roundup Power is expected to be approximately 4.2 lb/TBtu.

During combustion, mercury readily volatilizes from the fuel and is found predominantly in the vapor phase, as either elemental mercury or ionic mercury. Mercury speciation testing indicates that the distribution of ionic mercury (most likely mercury (II) chloride ($HgCl_2$)) and elemental mercury varies with coal type and boiler characteristics. Preliminary tests suggest that the chlorine concentration in the coal and the type of coal (e.g. bituminous, subbituminous, or lignite) may be associated with a particular speciation of mercury in the flue gas. Specifically, test results indicate that flue gas from subbituminous coals will contain significantly more elemental mercury than flue gas from bituminous coals, while higher concentrations of ionic mercury may be associated with bituminous coals, especially those with high chlorine concentrations. The EPA's Information Collection Request (ICR) testing results for the Mecklenburg, Logan, and SEI plants (for bituminous coal with average chlorine content of 1100 ppm) have indicated that collection efficiency upwards of 97% is possible. Similar mercury testing for emissions from Craig, Rawhide, and NSP Sherburne (for subbituminous coal with an average chlorine content of 170 ppm) have indicated that a collection efficiency of up to only about 36% is possible (average removal is 24.2%). According to the analyses conducted by Roundup Power, the Bull Mountain coal that would be used at Roundup Power has a maximum chlorine content of about 200 ppm. The typical chlorine content of the Bull Mountains coal will likely be less than 100 ppm. Chlorine content of coal appears to be an indicator of the amount of oxidized mercury that will be present in flue gas (i.e. the higher the chlorine content, the higher chance that the mercury will tend toward oxidized mercury and the lower the chlorine content, the higher the chance that the mercury will tend toward elemental mercury). National testing and research efforts have indicated that elemental mercury appears to be the most difficult form of mercury to control.

a. Emission Limitation Achieved In Practice by the Best Controlled Similar Source

Several studies are underway to identify control technologies that may effectively reduce mercury emissions. Most, if not all, of the technologies are in the research/development stage and are not currently commercially available. The particulate form mercury will be controlled as a trace metal (See Section IV.C.4). Some of the more promising mercury control technologies for elemental mercury and ionic mercury that have been identified by EPA are described below.

i. Activated Carbon Injection - Activated carbon injection is considered a potential control technology to enhance mercury removal from boiler flue gas. This technology involves the injection of activated carbon into the flue gas duct upstream of a particulate control device. Mercury is adsorbed to the surface of the activated carbon and subsequently removed in the downstream particulate control device. Preliminary data from various pilot-scale and bench-scale studies suggest several factors may affect the efficiency of activated carbon injection, including: (1) the temperature of the flue gas; (2) the speciation of mercury in the flue gas; and (3) the flue gas composition.

Pilot-scale studies of activated carbon injection upstream of an FF suggest that mercury removal efficiencies and the required amount of activated carbon are apparently temperature dependent. These tests suggest that more mercury is removed and less carbon is needed at lower flue gas temperature if the carbon is injected upstream of the particulate control. In many cases, flue gas temperatures must be maintained above a specific level to avoid acid condensation and, consequently, equipment corrosion.

Studies indicate that activated carbon injection may enhance removal of elemental mercury in an SDA/FF system. Removal may be further enhanced with the injection of iodide-impregnated or sulfur-impregnated activated carbon ahead of the SDA/FF system.

Roundup Power concluded that while activated carbon injection appears promising as a mercury control technology, more data and research into mercury speciation, flue gas composition, and the interaction of flue gas and mercury species at various conditions are needed to understand the factors that affect mercury removal. For these reasons, Roundup Power eliminated activated carbon injection as a MACT candidate for mercury control at this time. The Department's research into the use of activated carbon injection yielded the same conclusion--additional testing and research is necessary to determine the effects that mercury speciation, flue gas composition, and the interaction of flue gas and mercury species at various conditions will have on mercury collection efficiency. The Department agrees that activated carbon injection does not constitute MACT for Roundup Power.

Prior to issuance of the Initial Notice of MACT approval, the Department identified that the MidAmerican facility in Iowa was required by permit to use sorbent injection. According to the technical support document for that permit dated April 21, 2003, "The results of a review of the population of electric utility steam generating units showed that there were currently no units that have installed and are continuously operating any control system specifically for the removal of mercury from exhaust gases. However, the control equipment employed to remove other pollutants like SO_2 and PM/PM_{10} does remove some of the mercury from the exhaust gas. The available data on mercury removal is limited…Since there are no existing units operating with control specifically for mercury control, but rather are simply removing mercury as a co-benefit to the control of SO_2 and PM/PM_{10}, the Department has concluded that the co-benefits from the SO_2 and PM/PM_{10} control is the MACT floor."

That same document goes on to state "One technology has been identified as a potential beyond-the-floor control for mercury. That technology is sorbent injection…The applicant has agreed to install a sorbent injection system to remove the mercury from the exhaust of this unit."

The Department's review of other facilities yielded the same results as the review by the Iowa Department of Natural Resources in the MidAmerican case--the co-benefits from the SO_2 and PM/PM_{10} control is the MACT floor. Removal of mercury with sorbent injection, even at the MidAmerican facility, is not being achieved in practice because the MidAmerican facility is not constructed and is not operating. In addition, the MidAmerican technical support document identifies the sorbent injection technology as a potential beyond-the-floor control. Such language in the technical support document indicates that the technology is not mature (proven), which is exactly what the Montana Department's research has indicated. Therefore, the Department believes that the use of sorbent technology does not constitute the MACT floor and is not MACT for Roundup Power.

ii. FGD Systems - Ionic mercury is water-soluble, and therefore FGD systems may effectively remove ionic mercury from boiler flue gas. EPA's preliminary results from tests of wet and dry FGD systems indicate that up to 90% or more of the ionic mercury was captured by these systems. Elemental mercury typically is not removed effectively by FGD systems, although in pilot-scale tests, the removal efficiency of FGD systems varied widely. Results from EPA's case-by-case MACT tool also show this wide variation in removal efficiencies between elemental mercury and ionic mercury. For example, the case-by-case MACT tool predicted that a bituminous PC boiler with SDA, FF, and SCR controls would remove 97% of the flue gas mercury, while a subbituminous PC boiler with SDA, FF, and SCR controls would remove 23% of the flue gas mercury. The wide range in results suggests that the mercury speciation in the flue gas streams tested varied significantly and/or that other, poorly understood factors affect mercury removal mechanisms.

Roundup Power has indicated that the speciation of mercury in the flue gas may tend toward ionic mercury. The SDA FGD system that would be used to control SO_2 emissions should provide effective control of the ionic mercury in the flue gas. If the coal has low chlorine content, the speciation of mercury in the flue gas may tend toward elemental mercury. However, the SCR system that would be used to control NO_x emissions may oxidize some of the elemental mercury to ionic mercury, allowing it to be removed by the FGD system. More research is required before the level of elemental mercury oxidation can be estimated.

iii. Enhanced FGD Systems - Another category of mercury control involves the enhancement of existing FGD systems to improve the mercury removal rate. As discussed above, existing FGD systems should effectively remove oxidized (ionic) mercury from flue gas; therefore, methods to improve the capture of elemental mercury are being investigated by EPA and the scientific community. The primary options under investigation involve converting the elemental mercury to an oxidized form upstream of the FGD system for subsequent capture in the FGD system.

Similar investigations are also underway regarding the conversion of vapor-phase elemental mercury to more soluble ionic mercury. The primary process to oxidize elemental mercury involves passing the flue gas across a catalyst upstream of the FGD system. Conventional SCR systems may provide some oxidation of elemental mercury, and the effectiveness of a number of other catalysts is being studied. The effects of flue gas temperature and residence time on the oxidation potential of different catalysts and coal-based flue gases are also being evaluated.

According to Roundup Power, enhanced FGD technologies, while promising and potentially compatible with conventional pollutant control systems, are still in the demonstration phase and not a suitable candidate for a full-scale mercury MACT control system at this time. Based upon the Department's research, the Department agrees with Roundup Power's assertion that Enhanced FGD is not MACT.

iv. Combination of Conventional Pollutant Control Systems - Roundup Power proposed the use of SCR, SDA FGD, and FFs to control emission of criteria pollutants. The effectiveness of this combination of conventional control systems to reduce mercury emissions will depend on the speciation of mercury in the flue gas. According to Roundup Power, the boilers would burn coal that tends to speciate toward the ionic form, which is water soluble and effectively controlled in an FGD system. There is also a possibility that the SCR system may oxidize elemental mercury to ionic mercury. Finally, the high particulate matter control efficiency of the FFs (≈99.82%) should provide some additional mercury control. Therefore, Roundup Power proposed the combination of SCR, SDA FGD, and FFs as MACT for mercury.

The Department entered the Roundup Power facility specifics into EPA's "Case-by-Case MACT Tool" to determine the control efficiency that the program would predict. The Case-by-Case MACT Tool is a computer software model that predicts, among other things, mercury control efficiencies for various control equipment combinations. For Roundup Power, the program predicted that combustion of subbituminous coal, in conjunction with the facility controls, would yield a mercury control efficiency of 23% per boiler. The program was also used to predict that combustion of bituminous coal, in conjunction with the facility controls, would yield a mercury control efficiency of 97% per boiler. The Department used this program as an indicator of the effectiveness of the controls selected. A linear relationship does not appear to exist between percent control and coal type. Therefore, averaging the percent reduction of control for bituminous coals and the percent reduction of subbituminous coals is not appropriate.

Although Roundup Power has repeatedly identified the Bull Mountains coal as bituminous, the coal seems to more closely resemble subbituminous coal than bituminous coal (based on heating value and carbon content). Numerous definitions for bituminous and subbituminous coals were found. Among other definitions found, the Department found websites with information on these terms at the following sites:

www.google.com/search (define: bituminous coal and define: subbituminous coal)
www.ket.org/Trips/Coal/AGSMM/agsmmtypes.html
www.personal.psu.edu/users/b/w/bwt112/bituminous.htm
www.eia.doe.gov/cneaf/coal/page/gloss.html
www.worldbank.org/html/fpd/em/power/sources/coal_char.stm
www.personal.psu.edu/users/j/r/jrt163/egee/subbituminous.htm

A few of the descriptors found in the definitions for bituminous coals and subbituminous coals are:

> Bituminous Coals: Soft coal, 45-86% carbon and the most common type found in the United States…Generally has a heat content between 10,500 Btu/lb and 15,500 Btu/lb….moisture content is usually less than 20%.

Subbituminous Coals: A lower rank of coal (35-45% carbon) with a heating value between that of bituminous and lignite (usually 8300-11,500 Btu/lb). Contains a high percentage of volatile matter…contains 20 to 30 percent moisture.

Based on coal analyses on file with the Department, the average heating value of Bull Mountains coal is approximately 9200 Btu/lb, the carbon percentage is in the range of 55%, and the moisture is approximately 17%. Based upon these factors, the coal does not fit squarely into either of the coal type descriptors. A U.S. Geological Survey Professional Paper 1625-A on the Bull Mountain Basin written by G.D. Stricker was located on the internet by the Department. The paper describes the coal quality of the Bull Mountain coal based on coal samples. The paper describes the conclusion made by C.W. Connor in 1984 that the coal in the Bull Mountain Basin ranges in apparent rank from subbituminous A to high volatile bituminous C coal. The paper also describes that James Pontolillo and R.W. Stanton determined the thermal maturity level of the coal and that the levels are consistent with the apparent rank of subbituminous A to high volatile bituminous C coal.

v. Control Conclusions - The Department determined that the criteria pollutant controls required through the BACT analysis for Permit #3182-00 will also constitute MACT control for mercury emissions from the Roundup Power facility. Based on available information regarding mercury control, the Department determined that a mercury emission limit of 0.00000269 lb/MMBtu constitutes MACT. The emission limit is based on a mercury input value of 0.0000042 lb/MMBtu and a mercury removal efficiency of 36%. The mercury removal efficiency of 36% was chosen for several reasons: the Bull Mountains coal ranges from subbituminous A to high volatile bituminous C (collection efficiency will be closer to 23% than 97%); the highest removal efficiency achieved in practice by the best controlled similar sources (coal with similar characteristics--Craig, Rawhide, and NSP Sherburne) based on EPA data was approximately 36%, and collection efficiencies of greater than 36% are likely not possible for this facility. The Department determined that establishing a limit based upon bituminous coal properties was not appropriate since at most the coal is a low grade bituminous coal and because the coal is classified as a high grade subbituminous coal a large portion of the time. During neither those times when the coal would be classified as a high grade subbituminous coal nor those times when the coal would be classified as a low grade bituminous coal would the facility be likely to meet an emission limit based upon 97% control. As mentioned previously, a linear relationship does not appear to exist between percent control and coal type. Therefore, averaging the percent reduction of control for bituminous coals and the percent reduction of subbituminous coals is not appropriate. The Department determined that establishing the limit based upon similar facilities using subbituminous coals was most appropriate.

The emission controls and corresponding emission limit established by the Department for Roundup Power are consistent with recent MACT determinations, and the requirements are not less stringent than the emission limitations achieved in practice by the best-controlled similar sources (Craig, Rawhide, and NSP Sherburne). For example, the proposed mercury emission limit is lower than the proposed emission limits for Plum Point Energy, EnviroPower, Corn Belt Energy, Kentucky Mountain Power, Black Hills Corporation (Wygen 2), Thoroughbred Generating Station, and Tucson Electric (See Table 4), and the mercury emission limit is based on the highest level of control achieved in practice by the best-controlled similar source (36% by Craig).

Table 4. Recent Hg MACT Determinations and the Roundup Power Determination

Company	Hg Limit (lb/TBtu)	Control Technology
Plum Point Energy Associates, LLC – Plum Point Station	12.8	SDA, FF, SCR
MidAmerican Energy Company – Council Bluffs Energy Center	1.7	SDA, FF, SCR, ACI
EnviroPower of Illinois, LLC	No Limit	SDA, FF, SNCR
Corn Belt Energy Corporation – Elkhart	4.0	Wet FGD, Wet ESP, SCR
Kentucky Mountain Power, LLC	81	NIDS, FF, SNCR
Black Hills Corporation – Wygen 2	No Limit	SDA, FF, SCR
Thoroughbred Generating Station Company, LLC	3.21	Wet FGD, Wet ESP, SCR
Southern Illinois Power Cooperative	Not Addressed	Not Addressed
Tucson Electric Power Company – Springerville Generating Station	6.9	SDA, FF, SCR
Roundup Power Project	2.69	SDA, FF, SCR

Note: SDA – Spray Dry Absorber (dry FGD) FF – Fabric Filter
SCR – Selective Catalytic Reduction ACI – Activated Carbon Injection
ACI – Activated Carbon Injection SNCR – Selective Non-Catalytic Reduction
Wet FGD – Wet Flue Gas Desulfurization Wet ESP – Wet Electrostatic Precipitator
NIDS – Natural Integrated Desulfurization System

The mercury limit for MidAmerican is lower, but was based on using sorbent injection, a technology that was described in the MidAmerican technical support document as a "…potential beyond-the-floor control for mercury." That same MidAmerican technical support document goes on to state, "The available data on mercury removal is limited…Since there are no existing units operating with control specifically for mercury control, but rather are simply removing mercury as a co-benefit to the control of SO_2 and PM/PM_{10}, the Department has concluded that the co-benefits from the SO_2 and PM/PM_{10} control is the MACT floor." The Department reached the same conclusion--the co-benefits of other pollutant controls at Roundup Power represent the MACT floor for Roundup Power.

b. Costs of Achieving Emission Reductions

i. Activated Carbon Injection - The Department researched carbon injection further and found that activated carbon injection would likely be quite expensive. Cost is a factor in a MACT determination. MACT is defined in ARM 17.8.301 as follows:

> "…the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that the Department, **taking into consideration the cost of achieving such**

> **emission reduction**, and any non air-quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source of HAP." (emphasis added)

Cost was closely considered in other recently issued MACT determinations. For example, the Tucson Electric Power Company cost analysis for two PC units (each 400 net megawatts), indicated a cost effectiveness in excess of $30 million per ton of mercury reduction. The analysis for the Tucson Electric Power Company permit further notes that EPA determined a cost effectiveness of $9 million per ton was unreasonable for mercury control for hazardous waste combustors. The importance of this comparison was to show the cost per ton of mercury reduction that EPA has determined to be economically unreasonable for other sources. Since the cost per ton of mercury reduction for pulverized coal boilers is higher than the value determined by EPA to be unreasonable, the cost per ton of reduction for the pulverized coal boilers also seems to be unreasonable. Furthermore, EPA has not yet determined a cost effectiveness value for mercury reduction from utility boilers. Another cost analysis identified by the Department, for Plum Point Energy Associates, LLC (Plum Point), concluded that the cost effectiveness of using the least expensive carbon option would be $14.1 million per ton of mercury removed. Plum Point's analysis was based on up to two pulverized coal-fired boilers ranging from 550 to 800 megawatts. The agency determined that the cost per ton of reduction for carbon injection was economically unreasonable. Furthermore, information was submitted during the public comment period for Roundup Power's draft Case-by-Case determination that suggests a 90% removal efficiency using carbon beds, or activated carbon injection, or activated carbon injection with spray cooling would cost a minimum of $17,400 per pound of mercury reduced ($34,800,000 per ton of mercury reduction).

Roundup Power submitted information indicating that the cost of using activated carbon injection to control mercury emissions at the Roundup Power facility would cost between $28,500,000 and $50,000,000, depending on the activated carbon injection rate. The costs submitted by Roundup Power are similar to the costs identified by the Department for other recent MACT determinations.

Activated carbon injection is not a commercially proven technology for pulverized coal boilers, and the operating expenses are likely to be very costly. In addition, if the activated carbon material is classified as a hazardous waste, the higher disposal costs for the hazardous wastes will add significantly to the cost of this technology. The Department determined that the costs of achieving more rigorous controls than provided by the existing criteria pollutant emission controls would be economically unreasonable. Based on similar determinations by other agencies, the Department determined that the cost effectiveness of requiring activated carbon injection for mercury emission control from the Roundup Power main boilers is economically unreasonable.

Since the MACT controls for mercury would be the same control technology that was required in the BACT analysis for SO_2, PM_{10}, and NO_x, the costs of using this technology to control mercury would be economically reasonable. In order to maintain compliance with the SO_2, PM_{10}, and NO_x emission limits for the main boilers, Roundup Power will need to closely monitor the control equipment and maintain the equipment as appropriate. Increased preventive maintenance on the equipment will result in increased costs for achieving the MACT emission limits.

ii. FGD - The total annual cost for dry FGD for each main boiler was reported by Roundup Power to be $11,329,000. The cost effectiveness of using dry FGD for mercury alone would be $425,902,256 per ton of mercury reduction. This same annual cost equated to an SO_2 cost effectiveness of $393 per ton removed. Because dry FGD will reduce the emissions of mercury in addition to reducing the emissions of SO_2, the secondary benefit of dry FGD will be an economically reasonable method for mercury control. Because a dry FGD system will reduce the emissions of SO_2 in addition to reducing the emissions of mercury, the use of a dry FGD system becomes an economically reasonable method for mercury control. Without the added benefit of reducing SO_2 emissions, the use of a dry FGD system would not be economically reasonable for controlling mercury emissions.

iii. Enhanced FGD – The use of enhanced FGD is considered in the demonstration phase. At a minimum, the costs of using an enhanced FGD system will be equivalent to the costs of using traditional FGD. As shown in Section IV.C.5. b.ii, the cost of using traditional FGD solely for mercury control is economically unreasonable. The costs for enhanced FGD will be higher than the costs for FGD.

iv. Combination of Conventional Pollutant Control Systems – The use of a combination of conventional pollutant control systems would include the use of FGD, FF, and SCR. The costs associated with FGD were described in Section IV.C.5.b.ii. The use of an FF system in conjunction with the dry FGD system is essential in the collection of SO_2 and PM_{10} emissions. The total annual cost for FFs for each of the main boilers was reported by Roundup Power to be $4,063,000. The cost effectiveness of using FFs for mercury alone would be $152,744,360 per ton of mercury reduction. This same annual cost equated to a PM_{10} cost effectiveness of $31 per ton removed. Because an FF system will reduce the emissions of PM_{10} in addition to reducing the emissions of mercury, the use of an FF system becomes an economically reasonable method for mercury control. Without the added benefit of reducing PM_{10} emissions, the use of an FF system would not be economically reasonable for controlling mercury emissions.

The use of an SCR system in conjunction with the FF system and the dry FGD system will likely also provide some mercury control. The total annual cost for an SCR system for each of the main boilers was reported by Roundup Power to be $5,522,000. The cost effectiveness of using SCR for mercury alone would be $207,593,985 per ton of mercury reduction. This same annual cost equated to a NO_x cost effectiveness of $541 per ton removed. Because SCR will reduce the emissions of mercury in addition to reducing the emissions of NO_x, the secondary benefit of SCR will be an economically reasonable method for mercury control. Because an SCR system will reduce the emissions of NO_x in addition to reducing the emissions of mercury, the use of an SCR system becomes an economically reasonable method for mercury control. Without the added benefit of reducing NO_x emissions, the use of an SCR system would not be economically reasonable for controlling mercury emissions.

The mercury cost effectiveness calculations in this section are based on 36% mercury reduction and 0.0738 tons per year of uncontrolled mercury emissions per boiler. Although the control effectiveness for mercury is dependent on all three of the control systems mentioned earlier (FGD, FF, SCR), the costs of mercury control were separated for each control to demonstrate what the costs would be for that particular control for mercury.

Wet FGD and wet ESP are other criteria pollutant controls that would provide mercury control. The costs of using wet FGD and wet ESP were described in IV.C.2.b. The cost of using these technologies solely for the control of mercury would be economically unreasonable. To control mercury, the cost effectiveness would be $572,969,925 per ton (assuming total annual cost for wet FGD/wet ESP as 15,241,000 and 36% control). For numerous reasons, described in this MACT analysis, wet FGD/wet ESP was eliminated as a MACT option.

c. Non-Air Quality Health and Environmental Impacts and Energy Requirements

The non-air quality health, environmental, and energy impacts described in Section IV.C.1.c would also apply to the control technologies identified for mercury control (FGD and FF). The SCR system used for NO_x control may also increase the mercury control. The storage of ammonia on site for the SCR system creates the potential for accidents and an ammonia release. Depending on the type, concentration, and quantity of ammonia used, the material may be subject to regulation as a hazardous substance under CERCLA, Section 313 of the Emergency Planning and Community Right-to-Know Act, and Section 311(b)(4) of the Clean Water Act. Disposal of spent catalyst will also be required.

The use of activated carbon is another potential option for mercury control. Activated carbon control of mercury emissions may create a hazardous waste subject to the management and disposal standards of the Resource Conservation and Recovery Act (RCRA). According to Roundup Power, one of the issues yet to be resolved in connection with the use of activated carbon injection is whether the spent activated carbon will be listed as a hazardous waste. If the material is classified as a hazardous waste, the higher disposal costs will add significantly to the cost of this technology as described in Section IV.C.5.b of this MACT analysis.

The pollutants that are captured in the particulate control devices will contain elevated levels of HAPs. The disposal of the captured material will be required to comply with the applicable regulations.

D. Proposed MACT Determination

The Department determined that the design and operation of the boiler combustion systems, the requirements for the criteria pollutant control systems (SCR, SDA FGD, and FFs), the required SO_2 control efficiency, and the corresponding criteria pollutant emission limits constitute MACT for the control of HAPs. The Department determined that the emission limits and control efficiency requirements for criteria pollutants will serve as surrogate HAP limits for organic compounds, radionuclides, trace metals, and acid gases. In addition, the Department determined that specific emission limits were appropriate for HF, HCl, trace metals (arsenic, beryllium, cadmium, chromium, manganese, nickel, lead, and mercury. The Department determined that an emission limit of 0.00032 lb/MMBtu is MACT for HF, 0.0017 lb/MMBtu is MACT for HCl, 3.8E-03 lb/hr (9.41E-01 lb/TBtu) is MACT for arsenic, 1.2E-04 lb/hr (3.00E-02 lb/TBtu) is MACT for beryllium, 2.5E-03 lb/hr (6.30E-01 lb/TBtu) is MACT for cadmium, 1.1E-02 lb/hr (2.79E+00 lb/TBtu) is MACT for chromium, 3.1E-02 lb/hr (7.81E+00 lb/TBtu) is MACT for manganese, 1.1E-02 lb/hr (2.73E+00 lb/TBtu) is MACT for nickel, and 1.3E-02 lb/hr (3.36E+00 lb/TBtu) is MACT for lead.

Potential mercury emissions from Roundup Power are expected to be relatively low because of the low mercury content of the coal that will be used. Available coal analyses for Bull Mountains coal indicate that the mercury content of the coal (4.2 lb/TBtu) will be well below the average mercury content of other U.S. coal (7.7 lb/TBtu). For the reasons discussed previously, the technologies used to control criteria pollutants will also provide mercury control. Potential technologies that could provide additional mercury control are very expensive and/or still in the research and development stage and are not available commercially. Therefore, the Department determined that an emission limit of 0.00000269 lb/MMBtu (2.69 lb/TBtu) constitutes MACT for mercury and that the mercury control provided by the criteria pollutant emission controls is the appropriate MACT control. The emission limit for mercury is consistent with other recent case-by-case MACT determinations and is based on the control efficiency achieved in practice by the best controlled similar source.

V. Emission Inventory

Source	PM_{10} (tpy)	SO_2 (tpy)	NO_x (tpy)	VOC (tpy)	CO (tpy)	HAPs (tpy)	Pb (tpy)
Main Boiler #1 (MP-1)	245.5	1964.2	1145.7	49.1	2455.2	45.09	0.10
Main Boiler #2 (MP-2)	245.5	1964.2	1145.7	49.1	2455.2	45.09	0.10
Totals	490.1	3928.4	2291.4	98.2	4910.4	90.18	0.20

* A more thorough emission inventory is contained in the permit application for Permit #3182-00.

Main Power Boiler #1 (MP-1)

Fuel: Pulverized bituminous coal
Nominal Gross Plant Output = 390,100 kW
Nominal Net Plant Output = 350,172 kW
Maximum Short Term Primary Fuel Feed Rate = 202 ton/hr
Maximum Short Term Heat Input to Boiler = 4013 MMBtu/hr
Maximum Long Term Primary Fuel Feed Rate = 188 ton/hr
Maximum Long Term Heat Input to Boiler = 3737 MMBtu/hr
Sorbent Feed Rate = 10,332 lb/hr (45,255 ton/yr)
Annual Capacity Factor = 100% per year

PM_{10} Emissions

Emission Factor (uncontrolled) = 8.16 lb/MMBtu
Emission Factor (controlled) = 0.015 lb/MMBtu (permit condition)
Calculations: 0.015 lb/MMBtu * 4013 MMBtu/hr = 60.2 lb/hr (short-term limit)
0.015 lb/MMBtu * 3737 MMBtu/hr = 56.1 lb/hr (long-term average value)
56.1 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 245.5 ton/yr (annual limit)

SO_x Emissions

Emission Factor (uncontrolled) = 2.17 lb/MMBtu
Calculations: 0.15 lb/MMBtu * 4013 MMBtu/hr = 602.0 lb/hr (1-hr limit)
0.12 lb/MMBtu * 4013 MMBtu/hr = 481.6 lb/hr (24-hr limit)
0.12 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1964.2 ton/yr (annual limit)

NO_x Emissions

Emission Factor (uncontrolled) = 31 lb/ton (AP-42, Table 1.1-3, 9/98)
Emission Factor (unc.) = 31 lb/ton * 188 ton/hr * 1hr/3737 MMBtu = 1.56 lb/MMBtu
Emission Factor (controlled) = 0.07 lb/MMBtu (permit condition)
Calculation: 0.10 lb/MMBtu * 4013 MMBtu/hr = 401.3 lb/hr (1-hr limit)
0.07 lb/MMBtu * 4013 MMBtu/hr = 280.9 lb/hr (24-hr limit)
0.07 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1145.8 ton/yr (annual limit)

VOC Emissions

Emission Factor (uncontrolled) = 0.0030 lb/MMBtu (permit condition)
Calculation: 0.0030 lb/MMBtu * 3737 MMBtu/hr = 11.21 lb/hr (long term average value)
0.0030 lb/MMBtu * 4013 MMBtu/hr = 12.0 lb/hr (short term limit)
11.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 49.1 ton/yr (annual limit)

CO Emissions

Emission Factor (uncontrolled) = 0.15 lb/MMBtu (permit condition)

Calculation: 0.15 lb/MMBtu * 3737 MMBtu/hr = 560.55 lb/hr (long term average value)

0.15 lb/MMBtu * 4013 MMBtu/hr = 601.9 lb/hr (short term limit)

560.55 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2455.2 ton/yr (annual limit)

HAP Emissions

Total HAP emissions were determined for "unwashed coal." A summary of the calculations for the HAP emissions is contained in Permit Application #3182-00 (in Appendix B). The total HAP emissions are the sum of the total emissions from several tables in the appendix. HAPs = 45.09 ton/yr

The HAPs list for this facility includes the following pollutants:

Table 5. Main Boiler #1 HAPs

HAP	
Acetaldehyde	Formaldehyde
Acetophenone	Hexane
Acrolein	Hydrogen Fluoride (HF)
Antimony	Hydrogen Chloride (HCl)
Arsenic	Isophorone
Asbestos	Lead
Benzene	Manganese
Benzyl chloride	Mercury
Beryllium	Methyl bromide
Bis(2-ethylhexyl)phthalate(DEHP)	Methyl chloride
Bromoform	Methyl Ethyl Ketone
Cadmium	Methyl hydrazine
Carbon disulfide	Methyl methacrylate
2-Chloroacetophenone	Methyl tert butyl ether
Chlorobenzene	Methylene chloride
Chloroform	Nickel
Chromium	PAHs
Cobalt	Phenol
Cumene	Propionaldehyde
Cyanide	Selenium
2,4-Dinitrotoluene	Tetrachloroethylene
Dimethyl sulfate	Toluene
Dioxins/Furans	1,1,1-Trichloroethane
Ethyl benzene	Styrene
Ethyl chloride	Xylenes
Ethylene dichloride	Vinyl acetate
Etyylene dibromide	

Main Power Boiler #2 (MP-2)

Fuel: Pulverized bituminous coal

Nominal Gross Plant Output = 390,100 kW

Nominal Net Plant Output = 350,172 kW

Maximum Short Term Primary Fuel Feed Rate = 202 ton/hr

Maximum Short Term Heat Input to Boiler = 4013 MMBtu/hr

Maximum Long Term Primary Fuel Feed Rate = 188 ton/hr

Maximum Long Term Heat Input to Boiler = 3737 MMBtu/hr

Sorbent Feed Rate = 10,332 lb/hr (45,255 ton/yr)

Annual Capacity Factor = 100% per year

PM_{10} Emissions

Emission Factor (uncontrolled) = 8.16 lb/MMBtu
Emission Factor (controlled) = 0.015 lb/MMBtu (permit condition)
Calculations: 0.015 lb/MMBtu * 4013 MMBtu/hr = 60.2 lb/hr (short-term limit)
0.015 lb/MMBtu * 3737 MMBtu/hr = 56.1 lb/hr (long-term average value)
56.1 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 245.5 ton/yr (annual limit)

SO_x Emissions

Emission Factor (uncontrolled) = 2.17 lb/MMBtu
Calculations: 0.15 lb/MMBtu * 4013 MMBtu/hr = 602.0 lb/hr (1-hr limit)
0.12 lb/MMBtu * 4013 MMBtu/hr = 481.6 lb/hr (24-hr limit)
0.12 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1964.2 ton/yr (annual limit)

NO_x Emissions

Emission Factor (uncontrolled) = 31 lb/ton (AP-42, Table 1.1-3, 9/98)
Emission Factor (unc.) = 31 lb/ton * 188 ton/hr * 1hr/3737 MMBtu = 1.56 lb/MMBtu
Emission Factor (controlled) = 0.07 lb/MMBtu (permit condition)
Calculation: 0.10 lb/MMBtu * 4013 MMBtu/hr = 401.3 lb/hr (1-hr limit)
0.07 lb/MMBtu * 4013 MMBtu/hr = 280.9 lb/hr (24-hr limit)
0.07 lb/MMBtu*3737 MMBtu/hr*8760 hr/yr*0.0005 ton/lb=1145.8 ton/yr (annual limit)

VOC Emissions

Emission Factor (uncontrolled) = 0.0030 lb/MMBtu (permit condition)
Calculation: 0.0030 lb/MMBtu * 3737 MMBtu/hr = 11.21 lb/hr (long term average value)
0.0030 lb/MMBtu * 4013 MMBtu/hr = 12.0 lb/hr (short term limit)
11.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 49.1 ton/yr (annual limit)

CO Emissions

Emission Factor (uncontrolled) = 0.15 lb/MMBtu (permit condition)
Calculation: 0.15 lb/MMBtu * 3737 MMBtu/hr = 560.55 lb/hr (long term average value)
0.15 lb/MMBtu * 4013 MMBtu/hr = 601.9 lb/hr (short term limit)
560.55 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2455.2 ton/yr (annual limit)

HAP Emissions

Total HAP emissions were determined for "unwashed coal." A summary of the calculations for the HAP emissions is contained in Permit Application #3182-00 (in Appendix B). The total HAP emissions are the sum of the total emissions from several tables in the appendix. HAPs = 45.09 ton/yr
The HAPs list for this facility includes the following pollutants:

Table 6. Main Boiler #2 HAPs

HAP	
Acetaldehyde	Formaldehyde
Acetophenone	Hexane
Acrolein	Hydrogen Fluoride (HF)
Antimony	Hydrogen Chloride (HCl)
Arsenic	Isophorone
Asbestos	Lead
Benzene	Manganese
Benzyl chloride	Mercury
Beryllium	Methyl bromide
Bis(2-ethylhexyl)phthalate(DEHP)	Methyl chloride
Bromoform	Methyl Ethyl Ketone
Cadmium	Methyl hydrazine
Carbon disulfide	Methyl methacrylate

2-Chloroacetophenone	Methyl tert butyl ether
Chlorobenzene	Methylene chloride
Chloroform	Nickel
Chromium	PAHs
Cobalt	Phenol
Cumene	Propionaldehyde
Cyanide	Selenium
2,4-Dinitrotoluene	Tetrachloroethylene
Dimethyl sulfate	Toluene
Dioxins/Furans	1,1,1-Trichloroethane
Ethyl benzene	Styrene
Ethyl chloride	Xylenes
Ethylene dichloride	Vinyl acetate
Etyylene dibromide	

VI. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VII. Montana Environmental Policy Act

An Environmental Impact Statement (EIS) was completed for this project. The EIS is on file with the Department.

MACT Analysis Prepared By: Dan Walsh
Date: 07/10/03
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